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Developing an Optimization Model for a Cap and Trade System to Control Methane Emissions in the Oil and Natural Gas Industry. Application to the Permian Basin.

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Developing an Optimization Model for a Cap and Trade System to Control Methane Emissions in the Oil and Natural Gas Industry. Application to the Permian Basin.

by

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Dedication

To my lovely wife Carla R. Ketter who has always been by my side.

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Abstract

Developing an Optimization Model for a Cap and Trade System to Control Methane Emissions in the Oil and Natural Gas Industry. Application to the Permian Basin.

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Development of unconventional oil and natural gas in the U.S., particularly the exploitation of shale gas, has been highly controversial with significant geopolitical implications. It is unquestionable that this so-called "golden era" of natural gas has brought not only significant new technologies and economic growth but has also raised important environmental concerns, including air pollution from methane emissions.

Methane (CH_4) emissions from the oil and natural gas industry have been of critical and increasing concern for public policy. New evidence (Zeebe, et al. 2016) has confirmed record high levels of carbon dioxide (CO_2) in 66 million years, with CH_4 emissions considered a significant risk for global warming and climate change. For this reason, the U.S. Environmental Protection Agency (EPA) issued in 2016 a new "methane rule" to control emissions from the oil and gas industry by obligating the use of specific abatement measures to reduce pollution. This study analyzes the application of an optimization model to represent a market-based strategy of a cap and trade system as an alternative approach

to regulating emissions. This option is more efficient than traditional command and control regulations at achieving the same levels of methane reduction in the oil and gas sector, and this hypothesis is verified by applying the optimization model to a sample of oil and gas production facilities operating in the Permian Basin. In spite of all the political-scientific efforts and discussions, we are still far from the knowledge needed to achieve a public policy strategy that balances sustainability with economic development, and I hope this research helps to reduce that gap.

Table of Contents

List of Tables

List of Figures

Chapter 1: Introduction

INTRODUCTION

The development of unconventional natural gas has played a significant role in the U.S. economy, and it is considered one of the potential solutions for the nation to become independent of hydrocarbon imports. The natural gas consumption in the U.S. continues to show increasing trends while prices have been declining. Because of this so-called, "golden era" of natural gas, reserve estimation of this resource is a critical factor for defining future energy policies with significant economic and geopolitical implications. Horizontal drilling with hydraulic fracturing has triggered this "shale gas revolution" and it is considered one of the most important technologies in the development of energy markets in recent history. Shale gas in the United States has grown in less than a decade to represent about 50% of U.S. domestic production, and the export of liquefied natural gas (LNG) has become a highly promising economic opportunity during this shale gas revolution.

Environmental issues associated with U.S natural gas exploration and production, especially in unconventional shale plays, have significantly affected operator performance and technology development. Several lawsuits have been filed claiming that gas drilling contaminated residential water supplies and environment in general. Hydraulic fracturing of shale wells, popularly known as "fracking", requires a substantial amount of water per well, and in some areas because of severe drought, like Texas, shortages are a growing concern. Because of environmental apprehensions, the U.S. Department of Energy (DOE) issued a report in 2009 stating that the oil and gas industry would have to spend over ten billion dollars to comply with the environmental requirements set at that time.

Environmental risks associated with developing natural gas with hydraulic fracturing and horizontal drilling are evaluated in four major areas:

Water: Construction of wells, injections, use of freshwater, and wastewater disposal create risks of freshwater depletion, and contamination of groundwater, surface water, and drinking water.

Community: Increased earthquake events in some regions, such as Oklahoma and Texas have been a particular concern for the communities. Also, oil and gas operations have been associated with more traffic and increasing visual and noise pollution.

Land: The rapid expansion of drilling operations and well sites can temporarily damage landscapes, and affect the ecosystem in particularly sensitive regions.

Air: Onsite operations create potential emissions of volatile organic chemicals (VOCs), and greenhouse gasses (GHG) such as methane (CH4), nitrogen oxides (NOx), and other air pollutants.

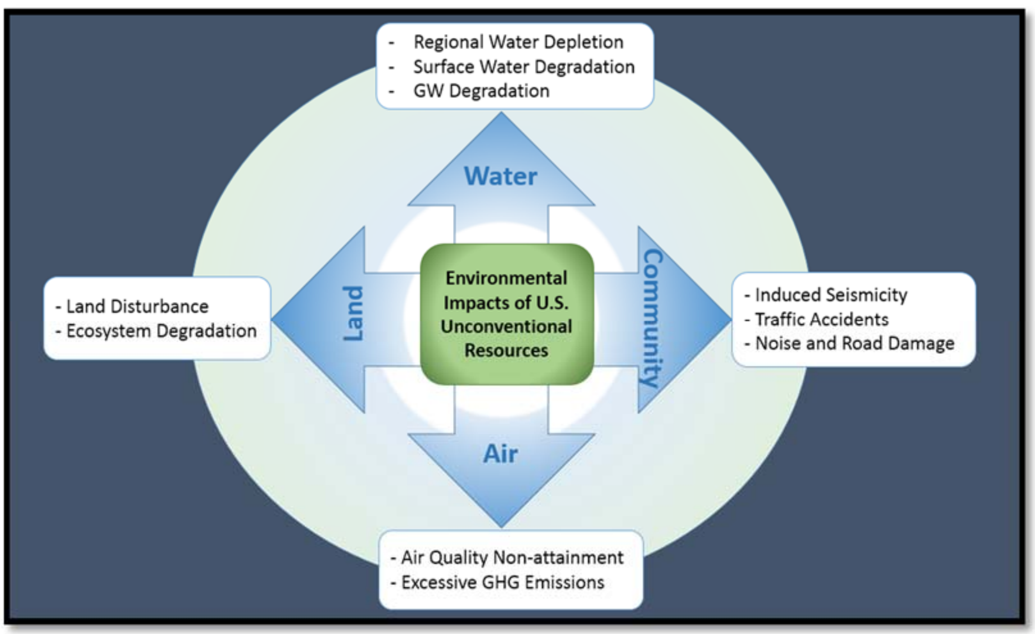


Figure 1. Environmental impacts of unconventional oil and natural gas resources.

Air pollution, and particularly, methane emissions from the oil and gas industry, has turned into a huge concern for policy makers, especially nowadays with carbon release rates from anthropogenic sources reaching a record high, and being unprecedented during the past 66 million years (Zeebe, et al. 2016).

In an effort to control air pollution, the Environmental Protection Agency (EPA) took a prescriptive command and control approach and in May 2016 issued what is called "the methane rule" which specifies the type of pollution-control devices to be installed by the industry to reduce emission levels.

Alternatively, market-based strategies, such as cap and trade systems, have proven to be a more efficient option than traditional regulation to control environmental problems, and they have been successfully adopted for pollution control in the United States for more than three decades (Schmalensee, et al. 2015). In 2009, a cap and trade plan (also known as Waxman-Markey plan) was the main policy proposed to address climate change, but this strategy failed to be included in the climate policy in the U.S. Senate in 2010 because the emphasis in public policy switched to health care as a national priority.

OBJECTIVES AND CHAPTER DESCRIPTION

The main purpose of this study was to develop and apply an optimization model to evaluate the performance of a firm participating in a cap and trade system in the oil and gas industry. Our hypothesis is that a market-based strategy should be a more efficient alternative than regulation for achieving same methane emissions reduction. The model was applied to the top facilities producing and generating methane emissions in the Permian Basin. The sample includes about 22 thousand wells producing since 1958 from about 37 thousand leases in Texas and New Mexico. The model estimates the minimum total cost of reducing a specific amount of emissions by either purchasing tradable permits in the market and by using abatement measures or self-purification strategies for years 2016 to 2020.

Chapter two discusses the relevancy of methane emissions in the oil and gas industry and analyzes both the contingency of pollution-control measures that have been proposed and implemented by the Government (EPA's "methane rule") and the basics of a cap and trade system.

Chapter three describes the model that was implemented, the area of study where it was applied and all the relevant variables and sample data that were used in this research.

Chapter four describes the parameters used for application of the model, the forecast of emissions for the period 2016-2020 based on gas production projected, and presents the results obtained for various scenarios with the corresponding sensitivity analysis.

Chapter five discusses the main implications for policy analysis and relevant conclusions of this study.

Chapter 2: Background

Shale gas is mostly methane (CH_4), extracted from rocks formed by the accumulation of sediments (sedimentary rocks) more than 300 million years ago. Shales formed by deposition of fine particles of silt and clay at the bottom of ancient seas, compression of these sediments under the weight of water, and other cementation of these sediments and other particles together. In this process of compression, organic matter (mostly marine microorganisms) were integrated into the forming rock, locked in the tight, low-permeability layers, exposed to increasing amounts of heat and pressure within the Earth's crust, and ultimately transformed into oil and gas. Because of the very low permeability and porosity of shales, mechanical stimulation – hydraulic fracturing – is required to extract hydrocarbons from the rock.

Hydraulic fracturing, popularly known as "fracking," is a technique that has been applied since the 1950's but only became popular at the end of the 1990's with the development of unconventional (shale) natural gas. Hydraulic fracturing is a technique in which the rock is fractured by a liquid injected at very high pressure, creating cracks in the rock formations through which natural gas and oil can freely flow. After the hydraulic pressure is reduced in the well, small grains of hydraulic fracturing proppants, such as sand and other aluminum oxides, maintaining open fractures once the rock achieves geologic equilibrium.

The use of hydraulic fracturing and horizontal drilling in developing unconventional reservoirs has impacted air pollution near extraction sites mostly by increasing methane emissions. CH_4 is a greenhouse gas that is more powerful and effective at trapping heat in the atmosphere than carbon dioxide (CO2). They are, however, much shorter lived than carbon dioxide. Methane is one of the most important GHGs after H2O vapor and CO2 with a Global Warming Potential (GWP) of 25. In other words, methane is 25 times as potent as CO2 on a 100-year timescale, and therefore CH_4 emissions can have a substantial impact on climate change threatening health and welfare of current and future generations. The oil and natural gas industry is the largest industrial source of methane in the world. Methane emissions have been a major concern for the U.S. Government and in May 2016, after five years of working on several regulations, the U.S. Environmental Protection Agency (EPA) finally issued the "methane rule" to reduce methane emissions from the oil and gas industry. Nevertheless, this issue is far from a final solution, and it will continue to be actively debated, we certainly will witness a very vigorous discussion on the efficiency of this regulation strategy to control emissions compared to alternative market strategies.

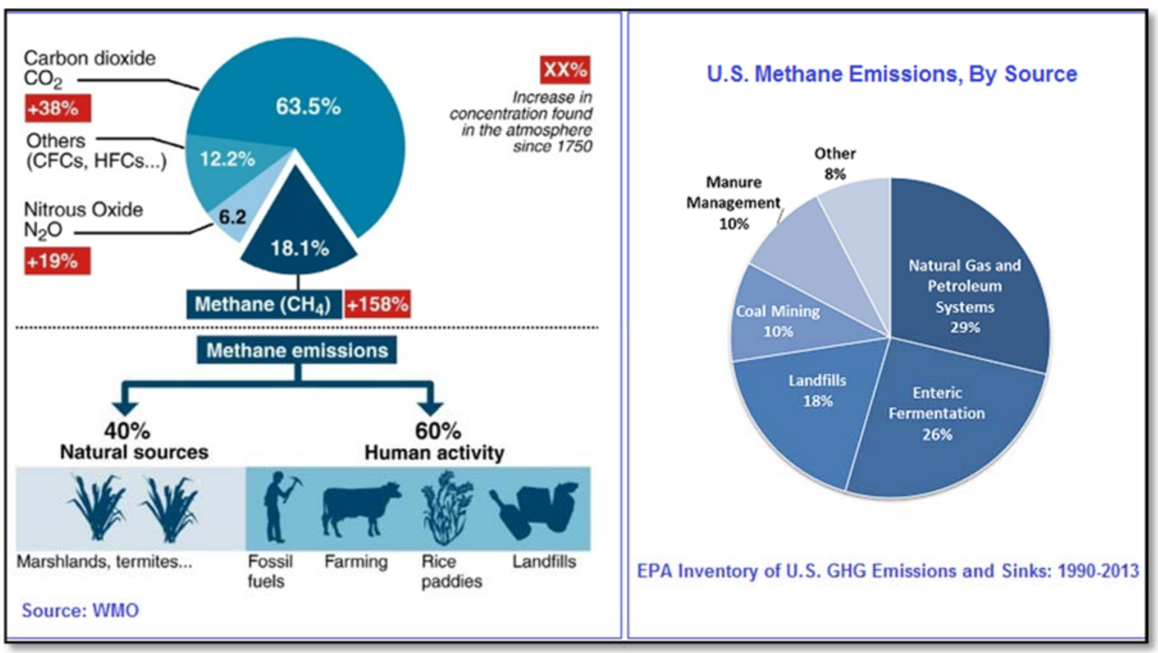


Figure 2: U.S. Methane Emissions by Source. EPA 2013, WMO.

According to the Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990-2013 EPA Report, the natural gas and petroleum systems are the largest industrial emitters of CH_4, accounting for about 30% of U.S. emissions.

Howarth et al. 2014 stated that CH_4 emissions from unconventional natural gas (shale gas) are significantly higher than emissions generated in the production of conventional reservoirs, concluding that the climate impact of shale gas may be greater than that of conventional fossil fuels. The authors also stated that methane emissions reported by EPA at drilling sites are drastically underestimated. Howarth's study has been considered controversial and highly disputed. K. Brown's article in "Energy in Depth", April 2014, for example, stated that the authors of the Howarth study are "well-known activists promoting the banning of hydraulic fracturing". Brown also indicates that in Howarth's study, researchers specifically targeted high emission areas, did not use direct measurements, considered small sampling, and, contrary to their findings, as natural gas production has gone up, we have observed that methane emissions have fallen dramatically.

In September 2013, The University of Texas at Austin released what has been considered one of the most comprehensive studies on methane to date (Allen, et al. 2013). This study took direct measurements of CH_4 from 190 natural gas production sites during completion operations for hydraulically fractured wells. One of the major findings of this study is that total annual methane emissions from all sources are "comparable" to EPA's estimates.

A more recent study (Zimmerle, et al. 2015) shows that the majority of methane emissions in oil and gas operations is most likely derived from flaring of gas and other actions, not accounted for in the EPA data.

From the discussion above, we can clearly observe that methane pollution associated with developing unconventional reservoirs has been and will continue to be highly debated, and certainly we will witness a dynamic discussion on this matter.

EPA "METHANE RULE."

For the last 5 years, EPA has been working on a comprehensive regulation ("Methane Rule"), as part of the President's Climate Strategy and the Clean Air Act to cut methane emissions from the oil and gas industry, and finally, in May 2016, the agency released the first set of standards and started the process to control emissions. This new rule was published on June 3 in the Federal Register and involves mostly the use and replacement of specific technologies for the four main segments of the natural gas industry: Production, Processing, Transmission and Storage, and Distribution. Figure 3 highlights the relative amount of methane emissions associated with each segment. According to the U.S. Greenhouse Gas Inventory Report: 1990-2013, methane emissions from natural gas systems totaled 157 million metric tons of carbon dioxide equivalent (mmtCO2e) in 2013, representing a 2% increase from emissions in 2012. Categorized by stage, methane emissions from the production stage totaled 47 mmtCO2e, while emissions attributed to the distribution stage totaled 33 mmtCO2e in 2013. Emissions increased 38% from gas processing between 2005 and 2013, from 16 to 23 mmtCO2e, respectively, and emissions from transmission and storage increased 11% between 2005 (49 mmtCO2e) and 2013 (54 mmtCO2e). Between 2012 and 2013, emissions from distribution increased 8%, from 31 to 33 mmtCO2e.

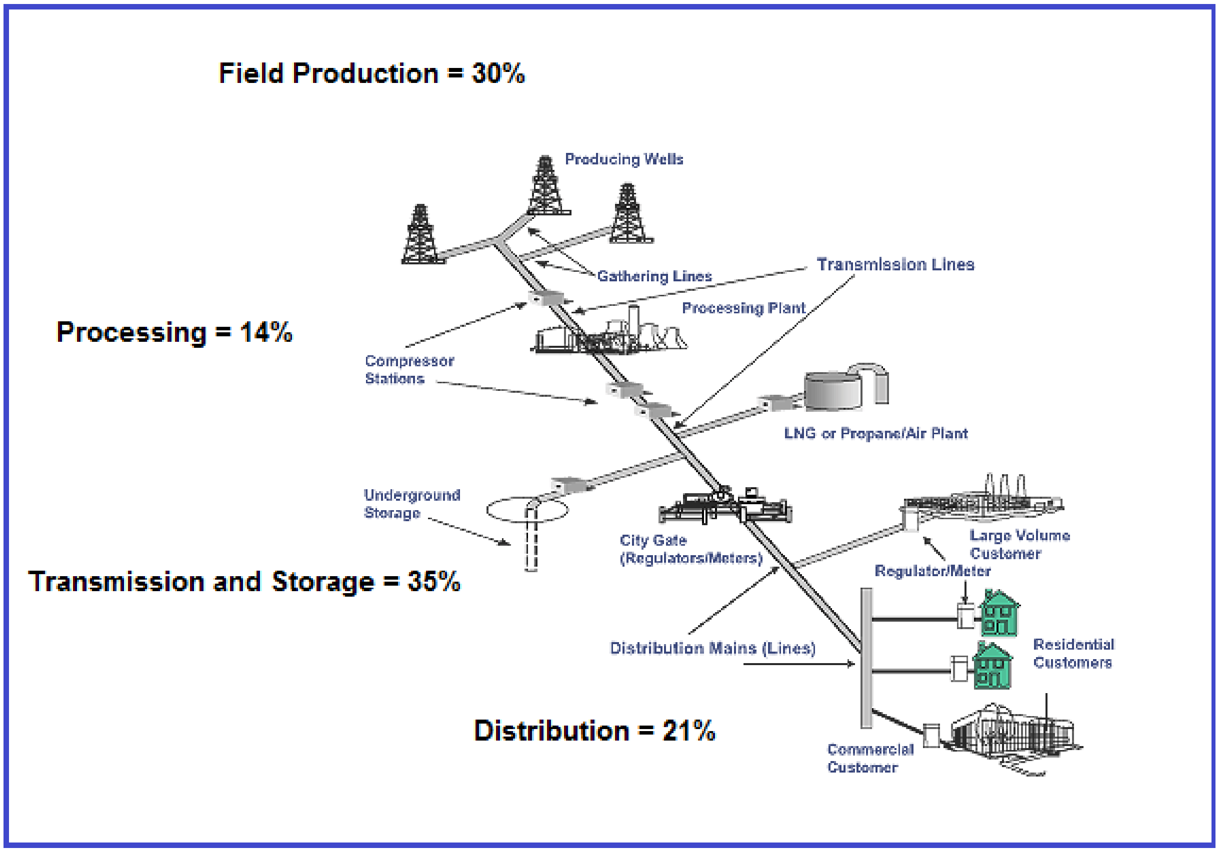


Figure 3: U.S. Methane Emissions Rates Associated to Each Stage.

According to EPA, methane emissions from the field production are primarily associated with pneumatic controllers and the hydraulic fracturing, completions and workovers of gas wells. Processing plants account for 14% of methane emissions and 58% of non-combustion carbon dioxide emissions from natural gas systems. Methane from processing increased as emissions from compressors increased because the quantity of gas produced also increased. EPA stated that compressors and dehydrators were the primary sources of methane emissions in the transportation and storage stage, accounting for 35% of total emissions from natural gas systems. Nevertheless, emissions decreased by 7% between 1990 and 2013 because of voluntary reductions (particularly the replacement of high bleed pneumatics devices with low bleed pneumatics). In the distribution stage, EPA indicated that the increased use of plastic piping had reduced both methane and CO2 emissions.

EPA reported that energy-related activities were the primary sources of anthropogenic GHG emissions in the U.S., representing about 85% of total GHG emissions on a CO2 equivalent basis in 2013. That figure included 97% of the nation's carbon dioxide emissions, 41% of methane emissions and 12% of nitrous oxide emissions.

The new EPA methane rule includes a comprehensive set of requirements that are amendments to the New Source Performance Standards (NSPS) for the oil and gas source category and prescribe new standards for both methane emission and volatile organic compounds (VOC) for specific equipment, processes, and activities as indicated below.

Rule Specifics

The principal amendments to the NSPS for the oil and natural gas source included in the EPA methane rule are the following:

Compressors. The Agency is proposing a 95% reduction of methane from wet seal centrifugal compressors across the source category by requiring that operators of these compressors to replace the rod packing with a process through a closed vent system under negative pressure. Reciprocating compressors prevent methane leakage by encasing each compressor rod with a set of oil-coated, flexible rings. Proper maintenance and routine replacement of these rings prevent unnecessary leakage of methane.

Pneumatic Controllers. The Agency is proposing a natural gas bleed rate limit of 6 standard cubic feet per hour, which will reduce methane emissions from continuous bleed, natural gas-driven pneumatic controllers. For the particular case of processing plants, EPA regulates methane emissions by requiring that natural gas operated pneumatic controllers have a zero natural gas bleed rate, as in the current NSPS.

Pneumatic Pumps. The standards for pneumatic pumps apply to particular types of pneumatic pumps across the entire source category. At locations other than processing plants, EPA is proposing that the methane emissions from natural gas-driven chemical or methanol pumps and diaphragm pumps be reduced by 95% if a control device is already on site. For the case of processing plants, the proposed standards require the methane emissions from natural gas-driven chemical or methanol pumps and diaphragm pumps to be zero.

Hydraulically Fractured Oil Well Completions. For subcategory one wells – non-wildcat, non-delineation wells – the Agency is proposing that for hydraulically fractured *oil well* completions, operators use reduced emissions completions, also known as ‘‘RECs’’ or ‘‘green completions,’’ to reduce methane emissions and maximize natural gas recovery from well completions. RECs are not required for hydraulically fractured *gas well* completions. For subcategory two wells – wildcat and delineation wells – EPA is proposing that for hydraulically fractured oil well completions, operators must use a completion combustion device to reduce methane. The proposed standards for hydraulically fractured oil well completions are the same as requirements for hydraulically fractured gas well completions in the 2012 NSPS and as amended in 2014.

Fugitive emissions from well sites and compressor stations. EPA is proposing the use of fugitive emission surveys for new and modified well sites and compressor stations (including transmission and storage, and the gathering and boosting segments) Semiannually optical gas imaging (OGI) technology surveys for well sites and compressor stations are being recommended. Fugitive emissions can occur at the startup of a newly constructed facility, as a result of improper connections and installation issues, or during operation. Under the new rule, the required survey frequency will decrease from semi-annually to annually for sites with emissions lower than 1%, while the frequency would increase from semi-annually to quarterly for sites with fugitive emissions from three percent or more of their emission during a survey. EPA will continue to encourage voluntary efforts to attain emission reductions through "responsible, transparent and verifiable" actions.

Other reconsideration issues being addressed. The Agency is proposing to address several other issues, such as storage vessel control device monitoring and testing provisions, record keeping for repair logs for control devices, flare design and operation standards, leak detection and repair for open-ended valves or lines, and disposal of carbon from control devices.

ENVIRONMENTAL ECONOMICS STRATEGIES: CARBON TAX VS CAP AND TRADE

As an alternative to the traditional command and control regulation, such as the EPA methane rule already in place, Environmental Economics Theory offers two other approaches to regulating air pollution problems more efficiently. These approaches include a carbon tax and a cap and trade system which are analyzed in the next section. The primary goal of this research is to propose, develop, and apply an optimization model to represent this market-based option of a cap and trade system.

Let us consider a basic situation with a single polluting company. Under this scenario, the company with an increasing marginal pollution abatement cost curve (red curve shown in Figure 5) will select to abate zero units of emissions in the absence of regulation, and will avoid the abatement costs given by the area below the marginal cost curve (B + C + D in the graph). Under a cost-benefit analysis, there is an optimal abatement amount, where the marginal benefit and marginal cost curves intersect. The resulting equilibrium level of emissions is X* (measured right to left in the horizontal axis).

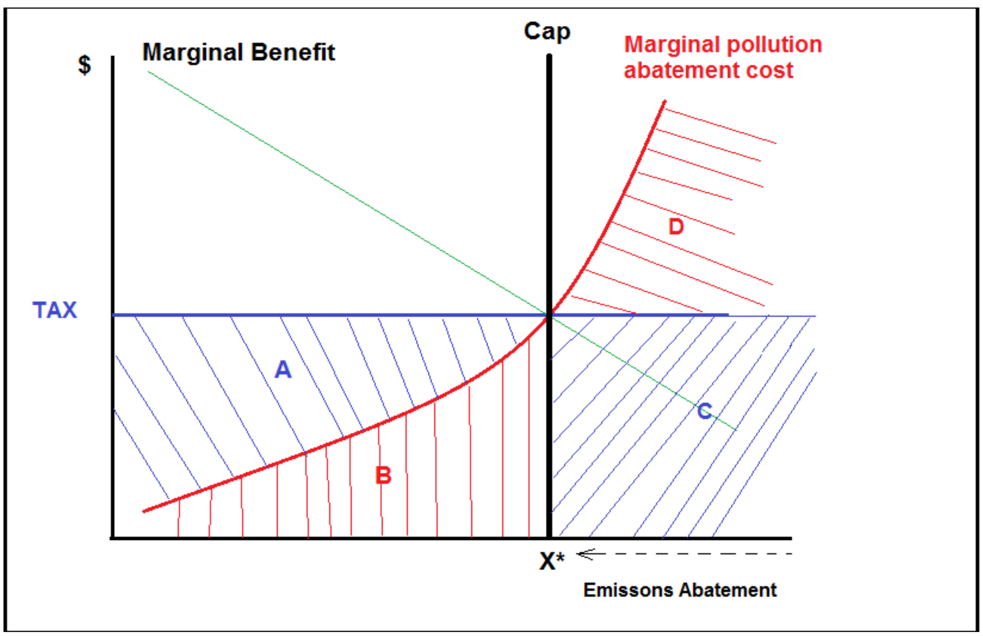


Figure 4. Cap and Trade versus Emission Tax.

Carbon Tax Policy

One possible alternative to achieve this level of abatement X* is by imposing a tax where marginal benefit equals marginal abatement cost, as shown in the graph by the horizontal tax blue line. For this polluting firm, it is less expensive to abate emissions as long as the marginal cost is lower than the tax. Because the tax cost (A+B) is greater than the marginal abatement cost (B) to the left of the cap line, the firm will choose to abate. To the right of the cap line the marginal abatement cost (C+D) is larger than the tax cost (C); therefore, the firm will choose to pay the tax and continue to pollute. In this case, the optimum abatement level of X* is achieved with a cost to the firm equals to B+C and government revenue of C.

Emission Cap

Another way to achieve the same level of abatement is to set a cap, where marginal benefit equals marginal abatement cost represented by the vertical cap line. The firm must abate to X* and, as a result, the optimum emission level is achieved with abatement cost to the pollution firm equals to B, which is lower than the previous strategy.

Cap and Trade Approach

To illustrate the cap and trade approach, let us extend the previous application to two polluting facilities with real data. Facility EP Energy and Facility Cimarex Energy Co. are two onshore petroleum and gas production facilities producing from the Permian Basin in Texas. Based on actual reports obtained from EPA sources, Facility EP generated a total of about 120,000 metric tons of carbon dioxide equivalent (TCO2e) of CH_4 emission during 2014. About 70% of emissions from this facility is caused by field production operation of 17 wells venting associated gas and 45 wells flaring associated gas.

Facility Cimarex generated a total of about 130,000 (TCO2e) of CH_4 emission during 2014. About 81% of the emissions is from natural gas pneumatic (high-bleed and intermittent bleed) devices.

Let us also consider that the regulator limits emissions of methane to 200,000 (TCO2e) in this region, setting this level as a cap and gives each facility two permits for 100,000 (TCO2e) each. Facility EP will require investing $3,000 per 10,000 TCO2e reductions (by replacing gas-assisted glycol pumps with electric pumps for example), and facility Cimarex needs to spend $1,000 for the same reduction rate (by increasing compression capacity to reduce venting and flaring). In the absence of a market-based alternative, the cost of reducing emissions and complying with the limit of 200,000 (TCO2e) will be $9,000; this is $6,000 for facility EP (reduction of 20,000 TCO2e) plus $3,000 for facility Cimarex (reduction of 30,000 TCO2e). Under the possibility of trading, we can observe that if facility Cimarex were to reduce 50,000 mtCO2e and company EP does not reduce its emissions at all, the cost would only be $5,000 for the same volume of reduction. By selling a permit to company EP for $5,000, Cimarex will recover expenses for the emissions reduction it would have to make to comply with the regulation, and the cost of the extra reduction made to trade with the other company. By buying a permit from Cimarex, EP saves $1,000 compared to making its reductions. As a consequence, the total cost of a decrease in a cap without any trade would be $9,000, whereas, under a cap and trade system, the total cost of compliance for both companies involved has been reduced to $5,000.

Based on this example, we observe that both the trade and nontrade scenarios generate the same reduction of emissions, but the first scenario is achieved at a lower short term cost for both facilities, this fact can also be demonstrated for the entire region. Given that the market-based strategy is more efficient than regulation, it is reasonable to question why the command and control approach is preferred to other alternatives. One of the possible answers is because environmental activists consider the market-based alternative creates a commodity out of pollution, frequently judged as a socially undesirable policy. Besides, cap and trade systems are considered vulnerable to manipulation by the political power of incumbent energy interest groups.

Main Conclusions

From the analysis above we can see that in the presence of negative externalities such as methane emissions, both a tax and a cap and trade will reach the same level of efficiency by obtaining the optimal reduction level at the minimum cost. The main difference is on distributional implications, and the cost to the firm is lower for cap and trade. The government receives revenue with the carbon tax strategy, and both policies are preferred over a command and control regulation. Polluting firms have an incentive to adopt new technology to reduce their marginal abatement costs with both a carbon tax and carbon tax and trade.

Carbon taxes and auctioned emission permits generate revenue for the government that can be applied to reduce a budget deficit or decrease distortionary taxes on labor and capital.

Market-based strategies, and particularly the cap and trade system, have been successfully implemented for several decades in the U.S. to control air pollution and next section summarizes the main lessons learned from previous experiences.

PREVIOUS EXPERIENCES OF A CAP AND TRADE SYSTEM: LITERATURE REVIEW

In September 2015, China announced the world's largest cap and trade program to reduce GHG emissions, the program will be launched in 2017 and will create a market for industries producing most of the CO2 emissions. This program definitely will impact future development of market-based strategies to control emissions, but it is not the first. Schmalensee et al., 2015, present an excellent overview of previous relevant experiences using cap and trade programs, being the following the most significant ones.

Trading emissions rights under the Clean Air Act – Acid Rain Program

Originally this program was intended to reduce sulfur dioxide (SO2) and nitrogen oxides (NOx) emissions from 1980 levels (Burtraw et al., 1998). A market of SO2 allowance trading emerged with cost savings of about $1 billion annually, compared with the expenses under command-and-control regulatory alternatives (Carlson et al., 2000). The program had a significant environmental impact, decreasing SO2 emissions significantly from the power sector from 1990 to 2005 (EPA, 2005).

The Regional Clean Air Incentives Market (RECLAIM) plan

Approved by the South Coast Air Quality Management District in October 1993, this plan set an emissions cap and a declining balance for most of the largest facilities emitting nitrogen oxides and sulfur oxides (SOx) in the South Coast Air Basin. RECLAIM included over 350 participants in its NOx market and about 40 participants in its SOx market. RECLAIM had the longest history and practical experience of any locally designed and implemented air emissions cap and trade program. RECLAIM allowed participating facilities to trade air pollution to meet clean air goals. The program aimed to provide the industry with flexibility to reduce emissions and generate advanced pollution control technologies. Allocations were issued to facilities based on their historic levels and appropriate emission control levels specified in the Air Quality Management Plan. Facilities have the option of complying with allowance by either reducing emissions or purchasing RECLAIM Trading Credits from other facilities.

NOx Budget Program

In 1999, under EPA guidance, 12 north-eastern states and the District of Columbia implemented a regional NOx cap and trade system to reduce compliance costs associated with the Ozone Transport Commission regulations stated in the 1990 Amendments to the Clean Air Act. Emissions limits for two zones from 1999 to 2003 were 35 and 45 percent of 1990 emissions, respectively. Compliance cost savings of 40–47 percent were estimated for the period 1999–2003, compared to a base case of continued command-and-control regulation without trading or banking (Farrell et al., 1999).

The Regional Greenhouse Gas Initiative

Nine northeastern U.S. states participated in the Regional Greenhouse Gas Initiative (RGGI), the first cap and trade system in the United States to address CO2 emissions. RGGI is a downstream program limited to the power sector. The program began in 2009 limiting ten emissions from regulated sources to current levels in the period from 2009 to 2014. The cap was then set to decrease by 2.5% each year from 2015 until it reached 10% below 2009 emissions in 2019. It was originally expected that meeting this goal would require a reduction approximately of 35% below business-as-usual emissions (13% below 1990 emissions levels). The program's auctions generated more than $1 billion in revenues for the participating states. Some of this revenue has gone to financing government programs to reduce energy demand and therefore CO2 emissions (Hibbard, et al. 2011).

California's AB-32 Cap and Trade System

California enacted Assembly Bill 32 (AB-32) in 2006, which required the California Air Resources Board to establish a program to reduce the state's GHG emissions to their 1990 level by the year 2020. The program included energy efficiency standards for vehicles, appliances, and buildings, low carbon fuel standard for refineries to reduce the content of carbon of motor vehicle fuels; and a cap and trade system (California EPA 2014). The AB-32 program began in 2013 with coverage of electricity sold in California and large-scale manufacturing. In 2015, it was expanded to include fuels, covering 85% of the emissions in the state. The 2013 cap was set at about 98 percent of anticipated 2012 emissions. Most allowances were initially distributed via free allocation and use of auctions over time. Through May 2015, the AB-32 cap and trade auctions had produced over $2 billion. Granting free allowances to facilities in particular sectors in proportion to their production levels contributes to output and impact directly competitiveness. On the contrary, giving allowances for free to firms in certain areas does not affect the receiving company's competitiveness, because its marginal production costs are unaffected.

The European Union Emissions Trading System (EU ETS)

This system is by far the largest current cap and trade program in the world for CO2 allowances. It was adopted in 2003 with a pilot phase that started in 2005 and covered half of EU CO2 emissions in more than 30 countries. There are over 11 thousand regulated emitters including electricity generators and large industrial sources. Competitiveness concerns were dealt with the allocation of free allowances to selected sectors. The program does not cover most sources in the transportation, commercial, or residential sectors, although some aviation sector emissions were included under the cap in 2012. The EU ETS has been extended through its Phase III, 2013-2020, with a more stringent, centrally determined cap (20% below 1990 emissions), a larger share of allowances to be auctioned, tighter limits on the use of offsets, and unlimited banking of allowances between Phases II and III. One of the main lessons learned from the EU ETS experience is that granting free allowances to selected sectors is a poor way to deal with competitiveness concerns, though it may serve as a useful political function. When allocations are not associated with production, they do not affect marginal costs. Thus, incentives to increase output or to relocate production or investment in other jurisdictions remain unaffected.

The EU ETS experienced serious problems in early 2013 when the market suffered a significant drop in prices (from $30 to about $8 per tonne). This decrease was the result of a massive overcapacity in the carbon market, caused partly by a general recession that reduced industrial demand for permits, and also because the EU handed out too many allowances at the beginning. Political bargaining, prioritizing national interests over others', and lobbyist loopholes have impacted negatively the success of the EU ETS system (The Economist, April 20th, 2013).

Chapter 3: Optimization Model

This chapter presents the optimization problem that an oil and gas facility needs to solve while participating in a potential cap and trade system.

As discussed before, the basic structure of a cap and trade system is very simple: total allowable emissions are limited (the cap), with an equivalent number of allowances created, and they may be sold on a market (the trade), the unused portion of the allowances can be traded to other companies struggling to comply or carried forward for future years. The cap and trade model, originally proposed by Dales in 1968, is a regulatory system focused on reducing pollution and to provide companies with a profit incentive to reduce their emission levels faster than their peers. Since firms minimize total production costs and considering that the market for these permits is competitive, it can be shown that overall cost of achieving the environmental standard will be minimized. As any other regulatory system, facility emissions are required to be constantly monitored to check for compliance.

Under a cap and trade system, operators are constrained to a total amount of emissions. They are allowed to acquire certified emission quotas on the market or invest in new technology to reduce emission levels to comply with the overall needs. The decision on purchasing permits or reducing emissions via investment in new technologies is a fundamental question, which can be modeled as a multi-stage optimization problem similar to Zhou, et al. 2015.

The following optimization model will be implemented to evaluate the company's decision of how much to invest in new and more efficient technologies to reduce emissions, and how many emission permits or certificates to buy in a likely cap and trade market for methane emissions in the oil and gas industry.

OPTIMIZATION MODEL

The non-linear (NLP) optimization model is based on minimizing the total cost of meeting the required emission over a specific period as follows:

$$\min Z = \sum_1^T \left\{ X_i^1(t)\ C^1(t) + C_j^2(t) \left(\frac{Q}{\delta}\right) \left[e^{\left(\frac{\delta}{Q}\right) \sum_{j=1}^{t} X_{ij}^2(t)} - e^{\left(\frac{\delta}{Q}\right) \sum_{j=1}^{t-1} X_{ij}^2(t)} \right] (1+k)^t \right\} \quad (1)$$

Subject to:

$$X_i^1(t) + X_{ij}^2(t) + l(t) \geq d_i\,(t)$$

$$l(t+1) = l(t) + X_i^1(t) + X_{ij}^2(t) - d_i\,(t) \quad (2)$$

$$\sum_1^T X_{ij}^2(t) = Q$$

Where:

$X_i^1(t)$ = emission quotas to be purchased in cap and trade market by facility i in year t

$X_{ij}^2(t)$ = emission reduction by facility i with investment in technology j in year t

Q = total emission reduction to be made for planning horizon

$C^1(t)$ = unit cost for purchasing emission quotas on the cap and trade market at year t

$C_j^2(t)$ = unit cost for reducing emission level via investment in technology j in year t

δ = parameter representing non-linear cost function of emission reduction via technology implementation

$l(t)$ = emission quotas available at the beginning of year t

$d_i\,(t)$ = demand per period for net required emission for facility i in year t

k = opportunity cost of investment

All methane emissions are reported in metric tons of carbon dioxide equivalent (TCO2e).

The first linear term in the objective function (1) represents the cost of buying emission certificates in the presence of a cap and trade market. The second non-linear term in equation (1) represents the cost of investing in new technology or abatement measures to reduce emissions. Therefore the solution of this model provides the minimum cost of achieving a total amount of emission reduction for the planned horizon.

The first set of constraints in (2) is to ensure that the sum of emissions purchased in the cap and trade system, the amount of emissions reduced by technology improvements, and the carryover meets the required emissions for each year for each facility. The second set is to represent unused emissions in one year that can be carried over to future years. The last constraint is to make sure that the total emissions reduction satisfies the goal set for the planning horizon.

Marginal Pollution Abatement Cost Curve

The non-linear term in the objective function represents the well-known concept of a marginal incremental cost curve, to model the cost of reducing emissions via technology improvement correctly. Abatement cost increases as accumulated emission reduction increases or in other words, the more reduced, the more difficult it is to reduce further. Figure 7 shows cost function. When total emission reduction is zero, which occurs at time t=1, the total cost C^2 equals C_0^2, for the following periods and as emission reduction increases, the cost of abatement also increases but at an exponential rate. Improvement cannot be indefinite because the abatement cost would also increase indefinitely.

The exponential terms within brackets in the second term of equation (1) represent the shaded area under the cost curve between points A and B. This is the total cost associated with abatement technology between two consecutive time periods. The value of parameter δ in the equation is the rate of change of the cost of specific abatement technology implementation.

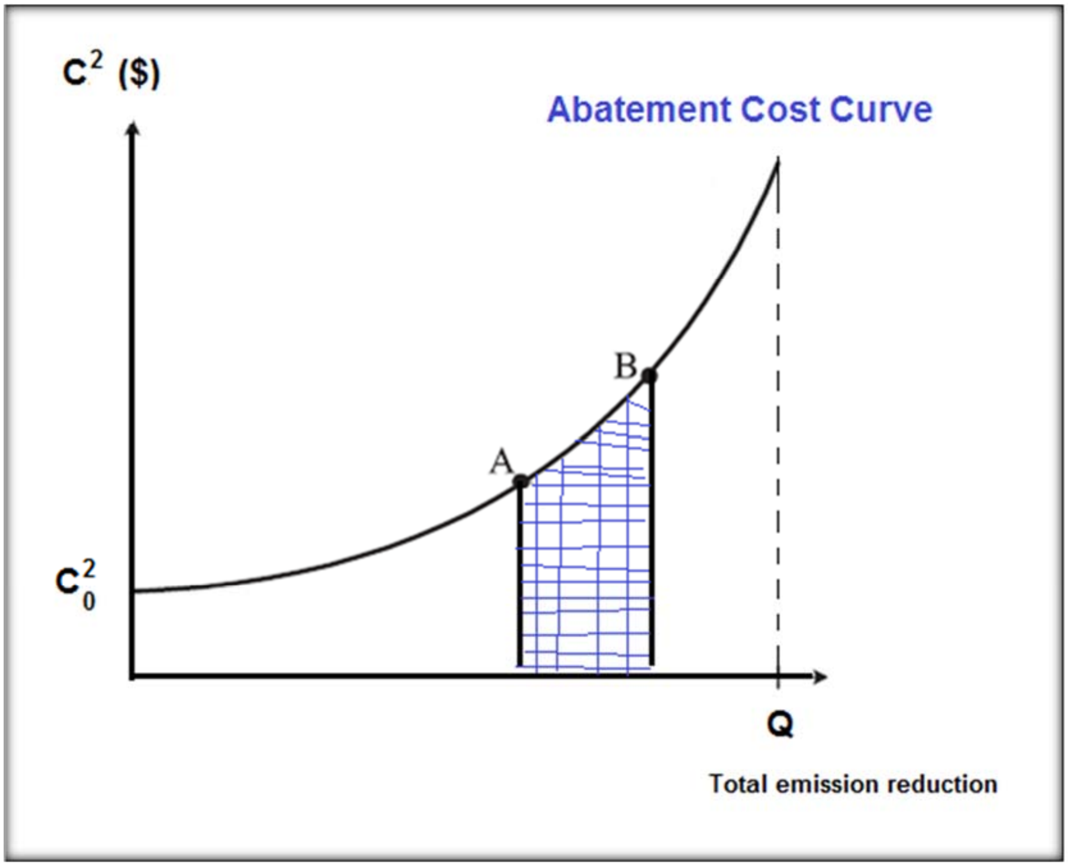


Figure 5. Abatement cost curve for reducing emission via new technology.

AREA OF INTEREST SELECTED: THE PERMIAN BASIN

The Permian Basin is considered one of the most potentially productive shale plays in the USA. It has generated about 31.5 billion barrels of oil and 112 trillion cubic feet of gas since 1921. A recent report from the USGS (November 15th, 2016) indicated that the Wolfcamp shale in the Texas' Permian Basin contains an estimated average of 20 billion barrels of oil, and 16 trillion cubic feet of associated natural gas. Current production is about 1.9 million barrels of oil (mmbo) and 6.6 billion cubic feet of gas (bcfg) per day (Berman, 2016). Scott Sheffield, Pioneer's CEO, said in July 2016, "The Permian is the mother lode. You factor in 4,000 feet of shales with 12 to 14 zones to play with...We'll be drilling that for the next 100, 150 years." The Permian Basin, located in West Texas and part of Southeastern New Mexico, covers about 250 miles wide and 300 miles long, and it includes about 43 counties in Texas and 5 in New Mexico. The basin is sub-divided into two basins: the Midland on the east and the Delaware on the west, separated by the Central Basin platform.

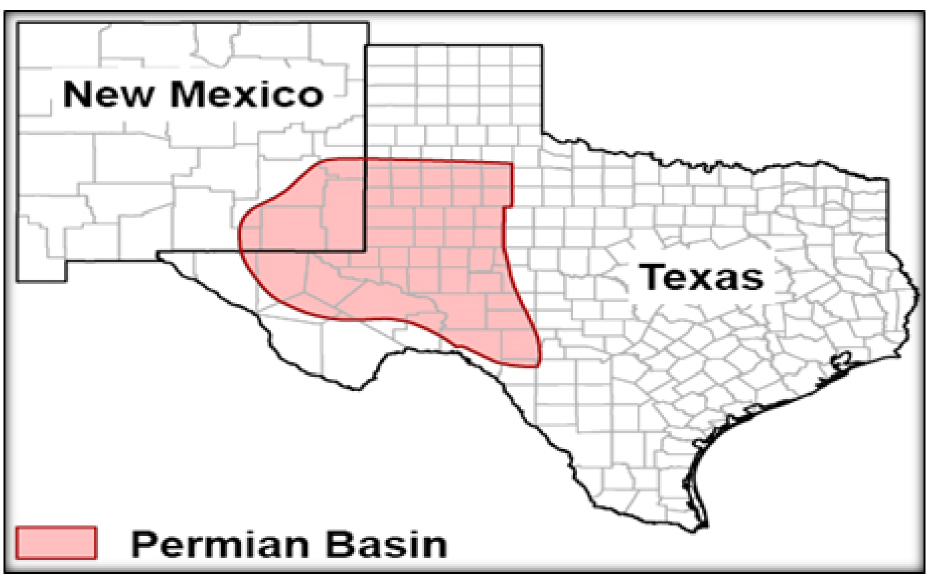


Figure 6. Permian Basin Map Location.

Geology of the Area

The Permian Basin covers one of the thickest deposits of Permian-aged rocks in the world. The basin was named after the period of geologic time – the Permian, occurred between 300 million to 250 million years ago where the basin reached its maximum depth: 29,000 feet.

The evolution of the basin is attributed to three distinct phases

1. Mass deposition
2. Continental collision, and
3. Basin filling.

Before the Permian Basin was created, this area was a broad marine region called the Tobosa Basin. During the Cambrian-Mississippian periods, 541 to 323 million years ago, a significant amount of sediments was deposited in this area forming a depression. The basin began building by the end of Mississippian and beginning of Pennsylvanian, 323 to 300 million years ago, when two supercontinents -- Laurasia and Gondwana -- collided to create Pangea. The area was covered by a seaway, and episodes of faulting, uplift, and erosion, as well as diverse rates of subsidence, caused structural deformations in the larger Tobosa Basin that divided it into sub-basins and platforms and finally created the filling of the sub-basins with sediments. The main sub-basins of the Permian are the Midland Basin and the Delaware basin, separated by the Central Basin Platform. The other main sections include the Northwest Shelf, Marfa Bain, Ozona Arch, Hovey Channel, Val Verde Basin, and Eastern Shelf. (Wright, 2011).

Deposition

The Midland and Delaware sub-basins are of the same age and lithology, but depths and development vary throughout the area. These sub-basins subsided, and the platform remained at a higher elevation. As a result, the area has very different water depths and depositional environments. The basins accumulated terrigenous clastics associated with deep water environments, whereas coarse grains associated with shallow reef environments were deposited along the platform (Sutton, 2015). Differences in sedimentary depositions and tectonics initiated stratigraphic discontinuities between the sub-basins.

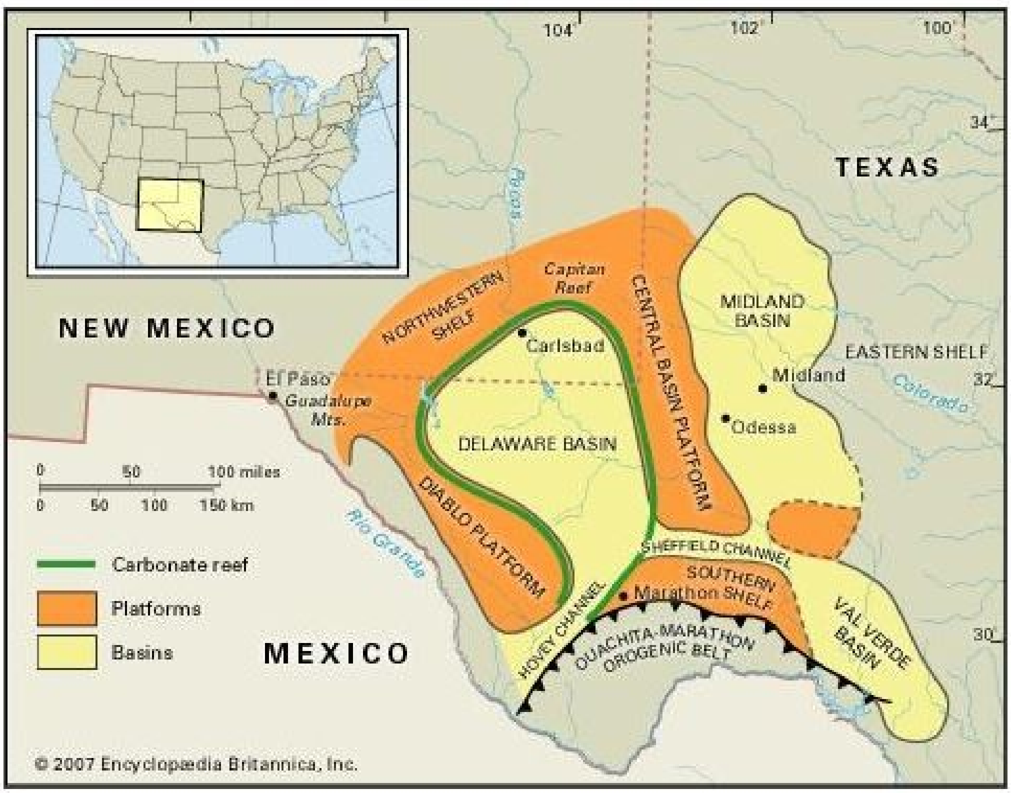


Figure 7. **C**omponents of the Permian Basin. Source: http://www.vyey.com.

The Midland Basin

The eastern Midland Basin accumulated large amounts of clastic sediments from the Ouachita orogenic belt during the Pennsylvanian occurred 323 to 299 million years ago. Sediments were deposited forming a deltaic system which drained the basin from east to west. During the Permian period, the delta system was covered with floodplains and nearly filled by the Middle Permian.

The Delaware Basin

The western area of the Permian Basin is the Delaware Basin, which is a structural and topographical low providing an inlet for marine water during most of the Permian. Secondary sedimentation was received from the low coastal plains surrounding the basin. While the Midland Basin was almost full of sediment by the Middle Permian, the Delaware became host to reefs built by microbial organisms, sponges, and algae. These organisms, along with the deep water inputs supplied by the Hovey Channel promoted carbonate buildups that formed a higher elevation area separating the shallow water and deep water deposits.

Depth is important to understand sediment deposition in the basin. The Delaware Basin is about 2,000 feet deeper than the Midland Basin consequently causing the sediments to experience almost twice as much pressure during burial. This is a leading factor in the stratigraphic discontinuities between the two sub-basins.

Drilling

The Permian Basin has been drilled since the 1920s with peak of oil and gas production by the early 70s. Drilling activity in the basin had steadily risen until the end of 2014. The Railroad Commission (RRC) of Texas reported more than doubling the permits issued for drilling from 2005 to 2012 and a notable increase in crude oil produced. Even now with low rig counts, the Permian Basin has more working rigs than any other field in the U.S. The Permian Basin is the most prolific oil producing basin in the United States, and it has the largest number of wells drilled in the nation with about 400,000 wells to date (Berman, 2016).

As Figure 8 shows, The US Energy Protection Agency tracks methane emissions for several Petroleum and Natural Gas System facilities through two programs: The GHG emissions and sinks (Inventory), and the GHG Reporting Program (GHGRP).

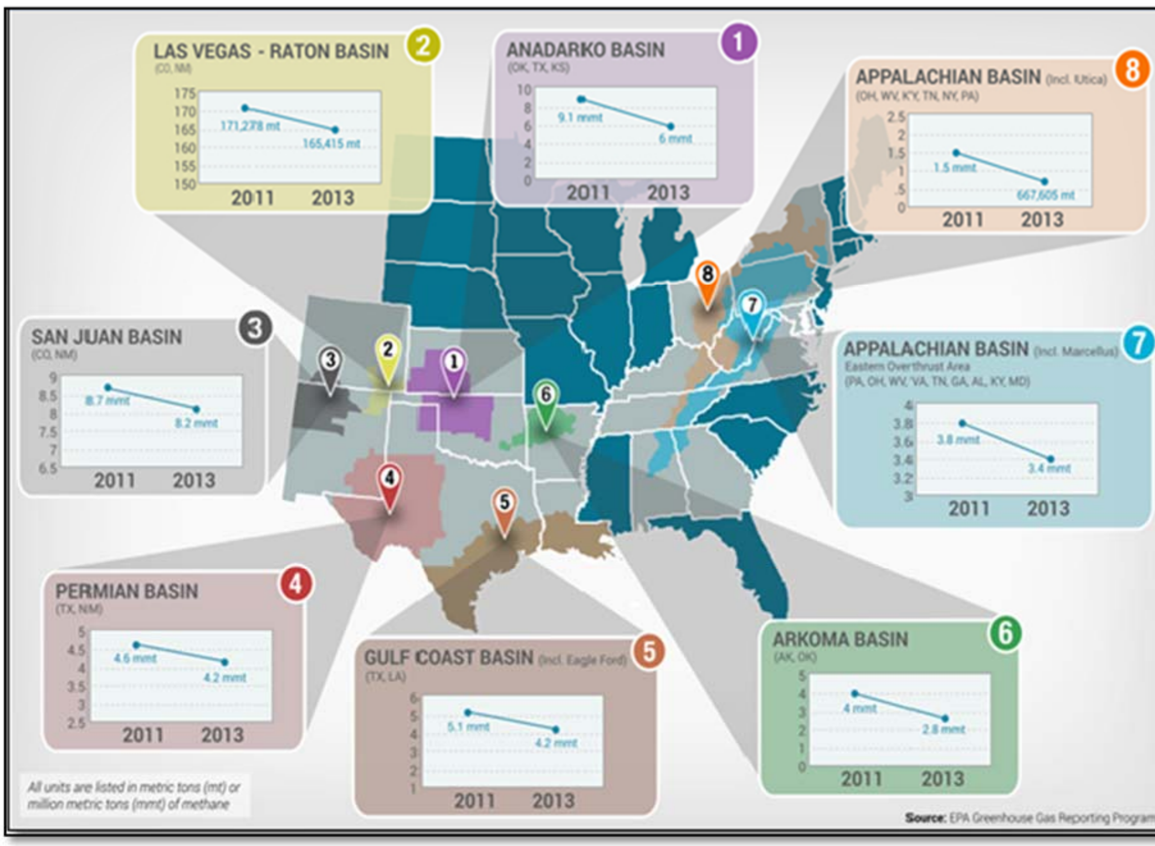


Figure 8. U.S. Methane Emissions by Basin. EPA Facility Level Information. GHG Tool (FLIGHT).

Sample Description

The year 2014 is considered as the base case, for this year EPA reported methane emissions for a total of 56 facilities producing from the Permian Basin, and these data are the basis for forecasts of future emissions and allowances for the period 2016-2020. The list of these facilities is given in Appendix A.

A total amount of 4.8 million of metric tons of CO2e were reported for these 56 facilities in 2014 and involved about 112,000 wells. For reference, this level of emissions is equivalent to CO2 emissions for electricity use from 700,000 of homes in one year, five billion pounds of coal burned, or 500 million gallons of gasoline consumed (EPA GHG Equivalencies Calculator). Appendix B presents a copy of the report of methane emissions for one particular facility obtained from the GHG EPA Tool (FLIGHT).

About 54% of the total emissions reported in the Permian Basin in 2014 is associated with leaks from natural gas pneumatic devices, the major source of emissions for 32 facilities.

Major Source of Emissions	Relative	Facilities
Natural Gas Pneumatic Devices	54%	32
Gas from Produced Oil Sent to Atmospheric Tanks	20%	6
Venting and Flaring	20%	9
Other Emissions from Leaks	7%	9
Total	100%	56

Table 1. CH_4 emissions sources for facilities reported in 2014 in the Permian Basin.

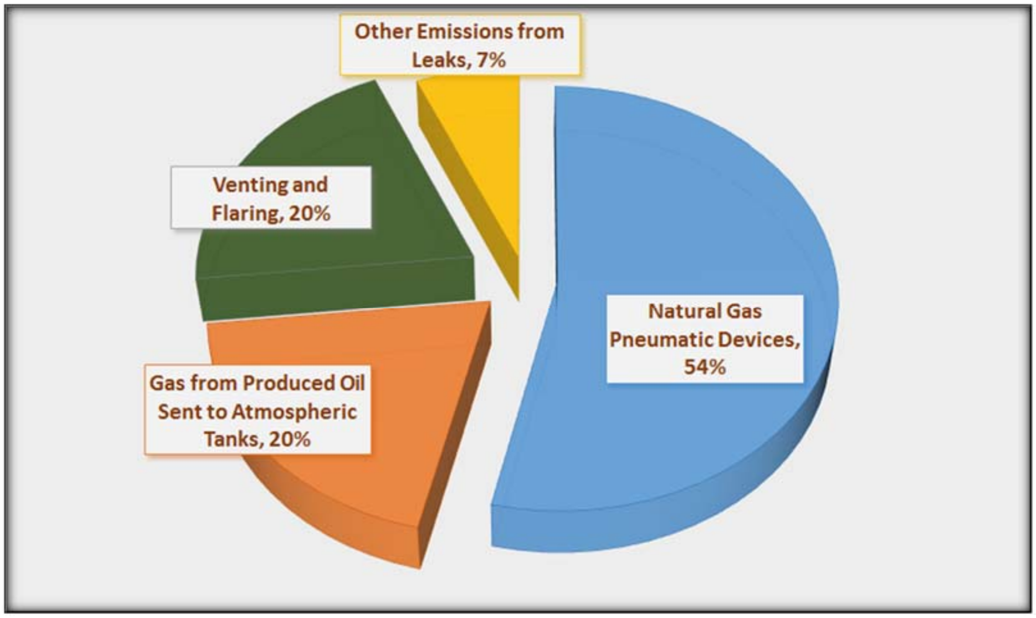


Figure 9. Major Sources of CH_4 emissions in the Permian Basin in 2014.

The three main sources of emissions indicated above are the potential technology improvements or measures that facilities need to invest in to reduce emissions. Therefore, the decision variable $X_{ij}^{2}(t)$ is the amount of emission reduction to be made by facility i with investment in technology to control emissions generated by (1) Venting and Flaring, (2) Pneumatic Devices, and (3) Atmospheric Tanks, for each of the five years projected.

The top eight facilities were selected as the final sample to run the optimization model. They account for half of the emissions reported in 2014 (2.3 million TCO2e). These eight facilities are listed in Table 1, and they include about 22,000 wells producing since 1958 in about 37,000 leases in the Permian Basin area.

Facility	Name	Methane Emissions (CO2e) (1)		Production Information (2)			Proportion
		Total CH4	Major Source	Leases	Wells	Total MCF Gas 2014	CO2e/MCF
1	Diamondback Energy	432,156	Venting and Flaring	1,067	855	17,597,362	2.46%
2	Cimarex Energy Co.	388,449	Pneumatic Devices	2,565	1,402	94,691,383	0.41%
3	EnverVest Operating L.L.C.	385,869	Pneumatic Devices	7,095	5,649	41,653,580	0.93%
4	COG Operating LLC	239,991	Atmospheric Tanks	8,894	5,853	147,399,340	0.16%
5	Yates Petroleum Corporation	227,661	Pneumatic Devices	3,699	1,796	28,699,833	0.79%
6	Endeavor Energy Resources LP	223,301	Atmospheric Tanks	9,618	4,888	25,551,291	0.87%
7	Devon Energy	215,920	Atmospheric Tanks	3,313	1,299	16,444,243	1.31%
8	Parsley Energy	196,632	Venting and Flaring	1,010	747	24,790,852	0.79%
Total		*2,309,979*		*37,261*	*22,489*	*396,827,884*	

(1) Data adquired from EPA Facility Level on GreenHouse Gases Tool (Flight) Source online: https://ghgdata.epa.gov/ghgp/main.do

(2) Data adquired from IHS-Enerdeq Database and PowerTool Software Ver 9.3

Table 2. Facilities selected for the model application.

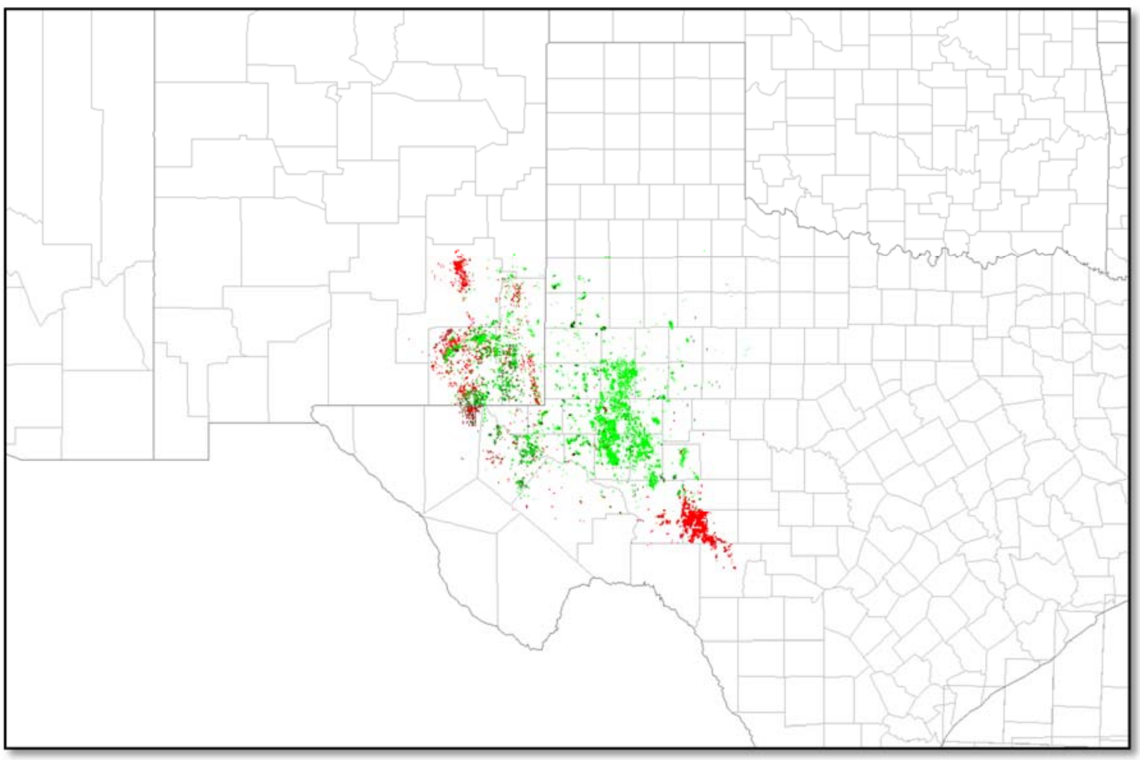


Figure 10. Leases selected for the sample. Red dots are gas wells, and green dots are oil wells. Map obtained from IHS-PowerTools Software.

ABATEMENT MEASURES TO REDUCE EMISSIONS

As previously indicated, three major abatement measures are considered as technology improvements to reduce emissions, and they are briefly described.

Pneumatic Devices

Emissions from these devices are one of the largest sources of vented methane emissions from the oil and natural gas industry, and as indicated before, they represent the major source of emissions in the Permian Basin. Pneumatic devices bleed or release natural gas to the atmosphere. EPA's new regulation requires reducing methane emissions by replacing high-bleed devices with low-bleed devices, retrofitting high-bleed devices, and improving maintenance practices. According to the Natural Gas STAR Program, high-bleed pneumatics are any device that bleeds more than six standard cubic feet per hour (scfh) or over 50 million cubic feet per year.

The natural gas industry uses several devices to automatically operate valves, control pressure, temperature, flow, or liquid levels. These devices can be controlled by electricity or compressed air, when available and economical. In the vast majority of applications, however, the gas industry uses pneumatic devices that employ energy from pressurized natural gas. Methane emissions from pneumatic devices are estimated at more than 50 billion cubic feet (BCF) per year only in the production sector, 14 BCF per year in the transmission sector and less than 1 Bcf per year in the processing sector.

Natural Gas STAR Partners have achieved significant savings and methane emission reductions through replacement, retrofit, and maintenance of high-bleed pneumatics. They have found that most retrofit investments pay for themselves in about a year and replacements in as little as six months. Up to date, Natural Gas STAR Partners have saved about 36 BCF by retrofitting or replacing high-bleed with low-bleed pneumatic devices, representing a savings of $255 million worth of gas. Individual savings will vary depending on design, condition, and specific operating conditions of the controller.

In the production sector, an estimate of about 400,000 pneumatic devices are being used and about 13,000 gas pneumatic devices in the processing sector.

In the transmission sector, about 85,000 pneumatic devices actuate isolation valves and regulate pressure and gas at compressor stations, pipelines, and storage facilities. Non-bleed pneumatic devices are also found on meter runs at distribution company gate stations for regulating flow, pressure, and temperature.

Field experience shows that nearly all high-bleed devices can be replaced with low-bleed equipment or retrofitted.

Gas Flaring and Venting

Gas is flared or vented mostly because the lack of access to pipelines or gathering lines to transport gas to processing plants. Gas flares emit both methane and black carbon. Methane emissions from gas flares are the result of incomplete combustion of the waste gas and thus are related to the destruction efficiency of the flares. Mitigation options are related to increasing gas utilization by re-injecting associated gas, minimize local on-site gas utilization, and maximize recovery.

Reducing the frequency of compressor startups avoids blowdowns and therefore reduces the volume of gas vented to the atmosphere with each startup. Poorly maintained ignition systems increase the incidence of failed engine starts and can stall the compressor once it is loaded. The compressor must then be unloaded and re-started. Each failed engine start wastes gas, produces unnecessary methane emissions, and reduces efficiency.

Remote production sites and compressor stations may vent low-pressure natural gas and vapors from storage tanks and other on-site equipment to the atmosphere, and emissions can be reduced by installing flares to combust these gasses instead of venting them directly to the atmosphere. Flaring technology typically consists of a small flare stack with one or two pilots and is normally installed on higher-pressure blowdown or emergency pressure relief valves for security reasons. Low-pressure gas installations are favored by environmental emissions control. For a single flare, methane emissions reductions of 2,000 MCF per year can be achieved with a single pilot. EPA estimates that costs for a flare are about \$3,000 and which vary significantly between \$1,000 and \$5,000 for different companies, fuel costs per year for each pilot is about \$1,800.

Emissions from Atmospheric Tanks

These are emissions from flaring that are reported as source-specific "vented to flare" for "gas from produced oil sent to atmospheric tanks" for the GHGRP subpart W recorded by EPA.

Natural gas pneumatic devices	**Associated gas venting and flaring**
Natural gas driven pneumatic pumps	Flare stacks
Acid gas removal units	Centrifugal compressors
Dehydrators	Reciprocating compressors
Well venting for liquids unloading	Other emissions from equipment leaks estimated using emission factors
Gas well completions and workovers	Local distribution companies
Blowdown vent stacks	Enhanced oil recovery injection pump blowdown
Gas from produced oil sent to Atmospheric tanks	Enhanced oil recovery hydrocarbon liquids dissolved CO_2
Transmission tanks	Onshore petroleum and natural gas production and distribution combustion emissions
Well testing venting and flaring	Offshore sources

Table 3. Emissions reporting categories reproduced from EPA FLIGHT tool.

Chapter 4: Model Application

As previously discussed, a firm participating in a cap and trade system must decide how much emission reductions to achieve with improvements in technology and by purchasing emission certificates in the market, therefore its strategy is represented as a cost minimization problem which can be solved by the non-linear optimization model described in the previous chapter. This chapter describes in more details the set of parameters considered to solve the problem and gives the results obtained for the period 2016-2020 for the sample selected.

PARAMETERS FOR THE MODEL

Demand for emissions (di)

This parameter is one of the most complex to estimate for the application of the model. It represents the demand of net required TCO2e methane emission for each of the eight facilities selected and for each of the next five years. The main assumption considered to estimate this parameter is that methane emissions are positively correlated with natural gas production. This hypothesis has been analyzed in various empirical studies and in general, they are consistent with the proposed positive correlation. Halley et al. (2014) investigated this relationship by using a multivariate linear regression, they found that emissions are positively correlated with gas production and about 10% of the variation in emission rates was caused by variation in production rates. In another study, scientists at Karlsruhe Institute of Technology (KIT), found a significant contribution of emissions from oil and gas production to methane levels since 2007, they stated that about 40% of the increase in methane emissions results from the increasing production of oil and natural gas in the northern hemisphere (Hausmann, et al. 2016). The positive relationship between gas production and methane emission was also confirmed for the sample selected by running simple linear regressions (with zero intercept, because the emission is null when no gas is produced). Regression coefficients (betas) for the eight facilities selected for the period 2011-2015 were obtained and are presented in Table 4. We can observe that methane emissions are positive and highly correlated to gas production for the sample, in the case of Parsley Energy, there was not enough emissions data available for previous years to compute this coefficient.

FACILITY	R Square	Coeff (Beta)	t-stat	Ratio CH4/MCF (2014)
Diamondback Energy	0.819	1.26%	2.02	2.46%
Cimarex Energy Co.	0.947	0.33%	5.90	0.41%
EnverVest Operating L.L.C.	0.993	1.12%	17.07	0.93%
COG Operating LLC	0.911	0.11%	4.42	0.16%
Yates Petroleum Corporation	0.928	1.30%	4.98	0.79%
Endeavor Energy Resources LP	0.996	1.01%	21.64	0.87%
Devon Energy	0.949	1.36%	6.05	1.31%
Parsley Energy	NA	NA	NA	0.79%

Table 4. Regression coefficients between CH_4 emissions and gas production for sample selected.

Emission forecast for next five years was estimated by applying the linear regression coefficient (beta) to production forecast for each year. These coefficients are assumed to be constant through time. In the case of Parsley Energy, the ratio between emissions and production for the year 2014 was used to forecast emissions for the following years.

By using the principle discussed above, the estimation of *di* requires forecasting gas production for every single well included in each facility for the next five years, and then aggregating all of the wells that belong to the same facility to finally obtain the total amount of emissions required by each facility per year. The final net emission requirement is computed by subtracting the total allowances given to each facility per year by a cap and trade system. As previous experiences of cap and trade systems (Schmalensee, et al. 2015) initial allowances could be an equal amount of emissions assigned to each facility, or allocations issued based on their historic levels. Allowances could be zero cost for facilities or auctioned. For the purpose of the model application, two cases of free allowances were considered:

Case 1: Equal amount of allowances based on emissions from major source reported in 2014, with a declining rate of 20% for following years after 2016.

Case 2: Allowances are equal to 2014 levels from major source reported for each facility and declining at a rate of 20% for each of the following years.

Each facility must decide the most efficient way to comply with its required amount of emissions for the planned time horizon by either reducing emission with abatement measures or more efficient technology and by purchasing additional emission certificates in the market. Facilities can carry forward unused allowances for future years.

Forecast of gas production for each well is traditionally performed by using decline curve analysis of historical production with Arp's equations. Published in 1945, Arps proposed a set of exponential and hyperbolic declining rate model to estimate future production. Arp's model was purely empirical and statistical, and it is represented by the equation (3).

$$q(t) = q_i(1 + b\,D_i t)^{-1/b} \qquad (3)$$

Where:

q(t) = rate of volume/time at time t

qi = stabilized rate of volume/time at time 0

b = Arp's decline constant

D = decline rate at time 0, 1/time

Decline curves can be one of three basic types depending on the value of b.

- Exponential when b equals zero,
- Hyperbolic when b is between zero and one, and
- Harmonic when b is greater that one.

For the application of this model, the software PowerTools v9.3 was used to compute the production forecast. The forecast is obtained by using what is called "expert fit" in the software which is based on Arp's equations and an advanced algorithm to curve fit the data. This routine initially fits the most recent production data (last 12 months) and calculates the Goodness of Fit. Then a sequence of iterative trial fits is performed by entering an additional month of earlier historical data and recalculating the Goodness of Fit. PowerTools selects the fit that produces the best Goodness of Fit from among all of the trials.

Once future gas production is estimated, regression coefficients indicated in Table 4 are applied to forecast emissions required (*di*) for the following five years (2016-2020). The following graph shows the production forecast obtained for one of the facilities selected in the sample. Appendix C gives the production forecast and decline curves for all of the selected facilities.

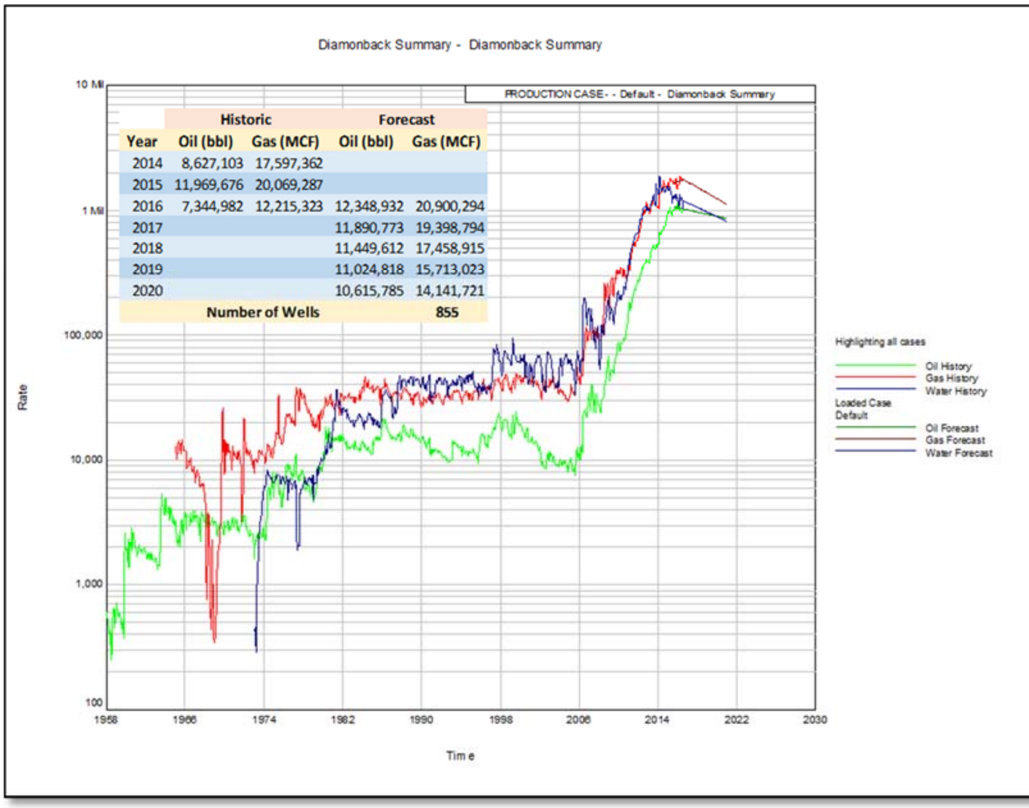


Figure 11. Forecast of production based on declining analysis. Facility: Diamondback Energy. Output modified from PowerTools v9.3.

Cost of emission reduction by technology improvement

The unit cost for reducing emission levels via investment in technology, C^2, is associated with three practices to reduce emissions cost-effectively: Venting and Flaring, Pneumatic Devices, and Atmospheric Tanks. The cost value of reducing a metric ton of CO2e for each of these practices is obtained from previous studies. For example, Carbon Limits (2012) states that the cost of gas venting and flaring control to reduce emissions ranges from $3 to about $60 per TCO2e for more than 850 cases evaluated (Figure 12 below). The cost of controlling/converting pneumatic devices from high bleed to low bleed rates average about $3 TCo2e under this study. Alternatively, Clean Air Task Force reported in March 2013 that based on EPA Natural Gas STAR Program technologies and practices, the average cost for controlling emissions from pneumatic devices is between \$39 and \$42 per metric ton of CO2e, and an average of \$34 for the case of oil tanks. Different cost levels are considered for this parameter in the sensitivity analysis to observe its impact on total optimum cost.

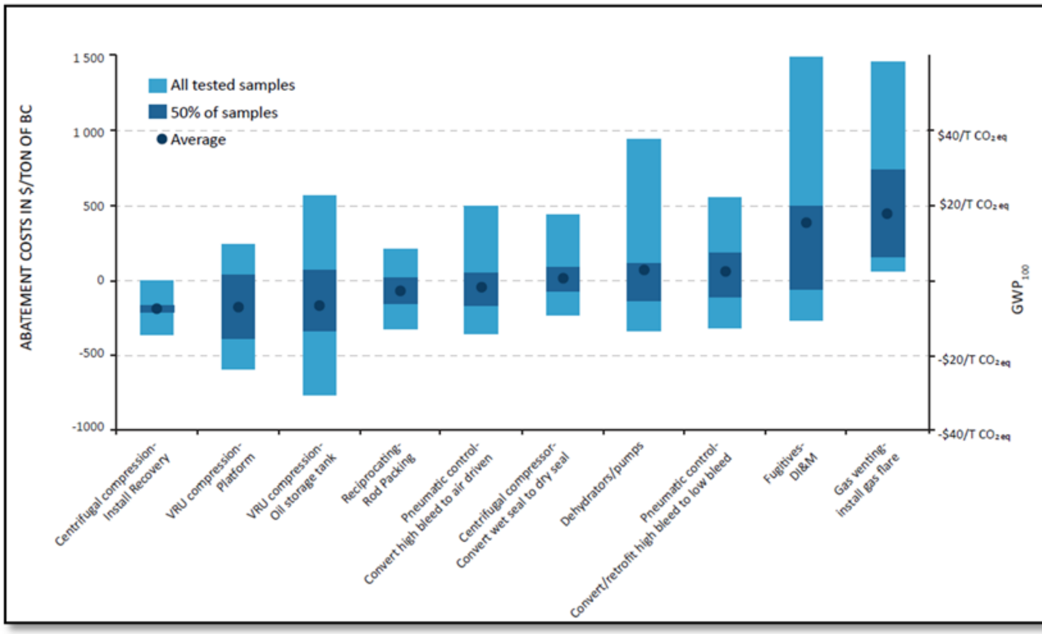


Figure 12. Abatement costs for methane emission reduction measures. Modified from Carbon Limits (December 2012).

Cost of emission certificates

This parameter (C^1) is trading price of emissions and is randomly generated by using a uniform distribution with values between \$15 and \$25 per TCO2e. These values are consistent with estimates of carbon dioxide prices forecasted for the year 2020 (Synapse Energy, March 2015).

Total of emission reduction (Q)

In August 2015, EPA stated that the Government expects to reduce emissions by 45% below 2012 levels by 2025. Following similar goals and for model application, *Q* is set to 50% of emission levels recorded in 2014 for the Permian Basin. This parameter could play an important role for optimality conditions, and it is also included in the sensitivity analysis.

Cost of Interest (k)

A rate of 5% is considered to represent the time cost of investment made on improvements for emission reduction, and it can be associated with a loan interest rate.

Parameters	Value	Unit
No of Periods	5	year
$C_{1(2016)}$	17	$/TCO2e
$C_{1(2017)}$	18	$/TCO2e
$C_{1(2018)}$	23	$/TCO2e
$C_{1(2019)}$	22	$/TCO2e
$C_{1(2020)}$	24	$/TCO2e
$C2_{(Venting)}$	50	$/TCO2e
$C2_{(Pneumatic)}$	40	$/TCO2e
$C2_{(Tanks)}$	35	$/TCO2e
Total Emissions (Q)	2,350,540	TCO2e
δ	1.2	
r	5%	

Table 5. Parameters for application of the model.

RESULTS

The following section presents the main results obtained by the optimization model run using the Excel Solver with the GRG Nonlinear engine. The basic model consisted of a total of 128 decision variables and 97 constraints. The parameters used to solve the problem are summarized in Table 5.

Table 6 and Table 7 present the forecast of gas production and total demand of emissions required for each facility per year. Emission allowances given to each facility have not been deducted yet. Therefore, based on projected gas production, the total amount of methane emissions required for the planning horizon is 9,219,626 TCO2e. This total minus the allowances awarded to each facility provide the net emissions required (*di*) which must be satisfied either by purchasing certificates in the market and by investing in one of the three abatement technologies considered.

Facility	Gas Production in MCF				
	2016	2017	2018	2019	2020
Diamondback Energy	20,900,294	19,398,794	17,458,915	15,713,023	14,141,721
Cimarex Energy Co.	135,194,839	115,440,946	100,668,451	89,208,605	80,009,063
EnverVest Operating L.L.C.	34,120,140	29,573,818	25,633,269	22,217,776	19,257,379
COG Operating LLC	172,678,695	159,260,535	147,778,190	137,840,784	129,156,070
Yates Petroleum Corporation	21,883,511	19,057,467	17,146,543	15,431,888	13,888,700
Endeavor Energy Resources LP	25,101,501	23,596,739	22,262,231	21,070,623	20,000,124
Devon Energy	14,003,050	11,755,193	9,868,177	8,284,076	6,954,264
Parsley Energy	34,145,313	32,305,787	29,075,208	26,167,687	23,550,919
Total	***458,027,343***	***410,389,279***	***369,890,984***	***335,934,462***	***306,958,240***

Table 6. Gas production forecast 2016-2020 based on Arp’s equation and historical data.

Facility	Total Demand of Methane Emissions in TCO2e				
	2016	2017	2018	2019	2020
Diamondback Energy	263,344	244,425	219,982	197,984	178,186
Cimarex Energy Co.	446,143	380,955	332,206	294,388	264,030
EnverVest Operating L.L.C.	382,146	331,227	287,093	248,839	215,683
COG Operating LLC	189,947	175,187	162,556	151,625	142,072
Yates Petroleum Corporation	284,486	247,747	222,905	200,615	180,553
Endeavor Energy Resources LP	253,525	238,327	224,849	212,813	202,001
Devon Energy	190,441	159,871	134,207	112,663	94,578
Parsley Energy	270,828	256,238	230,614	207,553	186,797
Total	***2,280,859***	***2,033,976***	***1,814,412***	***1,626,480***	***1,463,900***

Table 7. Forecast of methane emissions from gas production for 2016-2020.

Case 1: Equal emission quotas allocated for each facility

Under this case, the government gives each facility the same number of permits to emit, or allowances, based on actual emissions produced from major sources in 2014. These are free allocations, but facilities could buy auctioned allowances in the future. For this case and because I am considering only the top eight producers, each facility receives, initially for the year 2015, a total of 1/8th of the total 1,735,265 TCO2e, i.e., 216,908 TCO2e. Allowances for following years decline at a 20% rate from the previous year. Table 8 presents net emissions required for each facility.

Facility	Demand (*di*) of Methane Emissions in TCO2e				
	2016	2017	2018	2019	2020
Diamondback Energy	89,817	105,604	108,925	109,139	107,109
Cimarex Energy Co.	272,616	242,134	221,149	205,543	192,953
EnverVest Operating L.L.C.	208,619	192,406	176,036	159,994	144,606
COG Operating LLC	16,420	36,365	51,499	62,779	70,995
Yates Petroleum Corporation	110,959	108,926	111,848	111,769	109,477
Endeavor Energy Resources LP	79,999	99,506	113,792	123,968	130,925
Devon Energy	16,915	21,049	23,150	23,818	23,502
Parsley Energy	97,302	117,416	119,557	118,707	115,721
Total	***892,647***	***923,406***	***925,956***	***915,716***	***895,288***

Table 8. Net emissions required for each facility for case 1.

Table 9 and Table 10 summarize the main results obtained with the NLP optimization model, considering the case without the impact of capital cost, and with the inclusion of a 5% loan interest rate.

	X1= Emission Quotas to Purchase in Cap and Trade (TCO2e)				
Facility / Year	2016	2017	2018	2019	2020
Diamondback Energy	89,816	430,773	0	0	0
Cimarex Energy Co.	666,641	0	0	0	0
EnverVest Operating L.L.C.	414,302	0	0	0	0
COG Operating LLC	0	0	0	0	0
Yates Petroleum Corporation	82,228	0	0	0	0
Endeavor Energy Resources LP	0	0	0	0	0
Devon Energy	0	0	0	0	0
Parsley Energy	211,491	307,221	0	0	0
Total	1,464,479	737,993	0	0	0
	X2= Emission Reduction with Self Improvement (TCO2e)				
Facility / Year	2016	2017	2018	2019	2020
Diamondback Energy	1	1	1	1	1
Cimarex Energy Co.	13,913	104,669	1,468	178,487	169,216
EnverVest Operating L.L.C.	15,237	16,489	151,721	153,760	130,151
COG Operating LLC	23,444	37,354	55,064	63,440	58,756
Yates Petroleum Corporation	45,065	106,622	111,574	110,091	97,398
Endeavor Energy Resources LP	97,244	97,206	116,305	123,463	113,971
Devon Energy	17,734	23,083	20,298	33,883	13,436
Parsley Energy	1	0	32,776	0	17,214
Total	212,638	385,425	489,208	663,125	600,143
Total Cost (Z*) = $139,054,947					

Table 9. Values of decision variables for optimization model without cost of capital.

The total optimum cost under this case scenario is about $140 million and 27% of this cost is associated with purchasing emission certificates in the market. The total amount of emission reduction achieved is precisely the goal set at 2,350,540 TCO2e, and facilities obtain the difference (2,202,472 TCO2e) in the market.

As we can observe in this case without financial costs, facilities invest the smallest amount in emission reduction measures during the year 2016 (X_1^2 = 212,638), which is consistent with the fact that market prices in the cap and trade system are more attractive than investment in technologies for that particular year.

In the case of facilities Diamondback and Parsley, their major source of emissions is associated with venting and flaring activities, which has the highest cost of emission reduction with self-improvement actions. For this reason, we observe that the optimal value of emission reductions with self-improvement for them is marginal (X^2), and these two facilities satisfy most of the net emission requirements by purchasing certificates in the cap and trade system. It is important to note that, in the absence of a cap and trade system, these two companies would have to invest more to reduce emissions because they would not have any other choice. By testing different values for the abatement cost of venting and flaring, it was possible to compute that only when this technology has a cost lower than $40 per TCO2e these two facilities begin investing in self-improvement measures to reduce emissions.

The opposite occurs with facilities COG, Endeavor, and Devon. They are generating emissions mostly from gas sent to atmospheric tanks, which involves the cheapest abatement measure (C_3^2= \$35), and for this reason, we observe that these three facilities do not invest in the cap and trade market at all, and they satisfy all their emission requirements with self-improvement measures.

Another fact is that facilities select to purchase a large part of the emissions permits from the cap and trade market during the first year (2016) when market prices are the lowest and carry over the surplus for following years to satisfy future emission demands.

Table 10 shows similar results for the decision variable emissions certificates acquired in the cap and trade market (X^1) when a cost of capital of 5% is included.

	X1= Emission Quotas to Purchase in Cap and Trade (TCO2e)				
Facility / Year	2016	2017	2018	2019	2020
Diamondback Energy	89,818	430,771	0	0	0
Cimarex Energy Co.	651,680	0	0	0	0
EnverVest Operating L.L.C.	396,606	0	0	0	0
COG Operating LLC	0	0	0	0	0
Yates Petroleum Corporation	64,895	0	0	0	0
Endeavor Energy Resources LP	0	0	0	0	0
Devon Energy	0	0	0	0	0
Parsley Energy	237,750	330,952	0	0	0
Total	1,440,749	761,724	0	0	0
	X2= Emission Reduction with Self Improvement (TCO2e)				
Facility / Year	2016	2017	2018	2019	2020
Diamondback Energy	1	1	1	1	1
Cimarex Energy Co.	482,716	0	0	0	0
EnverVest Operating L.L.C.	485,054	0	0	0	0
COG Operating LLC	238,059	0	0	0	0
Yates Petroleum Corporation	488,083	0	0	0	0
Endeavor Energy Resources LP	548,188	0	0	0	0
Devon Energy	108,434	0	0	0	0
Parsley Energy	0	0	0	0	0
Total	2,350,536	1	1	1	1
Total Cost (Z*) = $144,136,504					

Table 10 Values of decision variables for model with 5% cost of capital.

When time cost of money (or interest rate) is included, it is reasonable to make larger investments (improvements) at earlier stages to avoid financial costs, in this case, all of the investment is made in 2016. X^2 for 2016 is about 2.4 million TCO2e (which is also the emissions reduction goal set for the planned horizon) when a 5% interest is considered, compared to only 212,000 TCO2e for the same year when zero interest cost is considered.

The total cost for the optimal solution when interest expenses are included is $144 million, and 26% of this cost is associated with purchasing emission certificates.

Case 2: Emission quotas allocated based on historical levels

In this case, the total amount of emissions reported from the major source in 2014, 1,735,265 TCO2e, are distributed to each facility based on historical levels for the year 2015, and allowances for following years decline at a 20% rate from the previous year. Net total emissions required is the same than the previous case but the distribution for each of them is different.

Facility	Demand (d_i) of Methane Emissions in TCO2e				
	2016	2017	2018	2019	2020
Diamondback Energy	-49,863	-6,140	19,530	37,622	49,896
Cimarex Energy Co.	200,633	184,547	175,079	168,687	163,469
EnverVest Operating L.L.C.	224,335	204,979	186,094	168,040	151,044
COG Operating LLC	43,569	58,085	68,874	76,680	82,116
Yates Petroleum Corporation	149,035	139,386	136,216	131,264	125,072
Endeavor Energy Resources LP	120,144	131,622	139,485	144,522	147,368
Devon Energy	85,662	76,047	67,148	59,016	51,660
Parsley Energy	119,132	134,880	133,528	129,884	124,662
Total	***892,647***	***923,406***	***925,956***	***915,716***	***895,288***

Table 11. Net emissions required for each facility for case 2.

We observe that in this case 2 and for Diamondback facility, the parameters d_i for 2016 and 2017 are negative, which indicates that the allowances assigned to this firm in those two years (313,206 and 250,565 TCO2e) were higher than the expected emissions required (as shown in Table 7, i.e., 263,344 and 244,425 TCO2e respectively). Therefore this company will carry over the surplus to satisfy emissions needed for the following years.

Results of the optimal solution for this case are a little different than those for Case 1, particularly for cap and trade purchasing. Facilities prefer to invest in cap and trade emission certificates at later periods, but for investment in self-improvement technologies, they realize the investment in the early stages, similar to the previous case, to avoid financial costs. Same as before, Diamondback and Parsley Energy satisfy all the emissions required by purchasing in the cap and trade market, whereas Devon and COG reduce emissions only by investing in abatement technologies.

	X1= Emission Quotas to Purchase in Cap and Trade (TCO2e)				
Facility / Year	**2016**	**2017**	**2018**	**2019**	**2020**
Diamondback Energy	1	1	1	51,040	0
Cimarex Energy Co.	0	223,836	0	168,687	163,469
EnverVest Operating L.L.C.	203,946	0	0	168,040	151,044
COG Operating LLC	0	0	0	0	0
Yates Petroleum Corporation	26,617	0	0	131,264	125,072
Endeavor Energy Resources LP	0	0	0	0	147,368
Devon Energy	0	0	0	0	0
Parsley Energy	119,132	134,880	133,528	129,884	124,662
Total	**349,695**	**358,717**	**133,529**	**648,915**	**711,616**
	X2= Emission Reduction with Self Improvement (TCO2e)				
Facility / Year	**2016**	**2017**	**2018**	**2019**	**2020**
Diamondback Energy	1	1	1	0	0
Cimarex Energy Co.	200,633	135,791	0	0	0
EnverVest Operating L.L.C.	411,462	0	0	0	0
COG Operating LLC	329,324	0	0	0	0
Yates Petroleum Corporation	261,804	0	136,216	0	0
Endeavor Energy Resources LP	120,144	131,622	139,485	144,522	0
Devon Energy	339,534	0	0	0	0
Parsley Energy	0	0	0	0	0
Total	**1,662,902**	**267,414**	**275,702**	**144,522**	**0**
Total Cost (Z*) = $152,563,638					

Table 12 Values of decision variables for Case 2 with cost of capital of 5%.

The optimal solution in this Case 2 is less efficient than the previous one, about \$8.4 million more expensive for the same amount of emissions reduction. In any case, it is important to note that the equilibrium allocation of pollution permits, after trading in the market has occurred, is independent of the initial allocation, therefore the initial allocation of allowances is designed more oriented to maximize political support without compromising the system's environmental performance or raising its cost (Montgomery, 1972).

SENSITIVITY ANALYSIS

All of the sensitivity analysis was performed using the case 1 scenario for allowances and including the cost of capital of 5%.

Sensitivity on Self-improvement Cost (C^2)

Numerical experiments are applied to each abatement measure independently and considering facilities which major emissions are associated with that particular technology.

Abatement Measures for Controlling Emissions from Venting and Flaring

Diamondback and Parsley are the two facilities generating emissions from venting and flaring as the major source. The abatement cost for reducing emissions in the base case is \$50 per TCO2e, and it is the highest cost of the three technologies considered. Therefore, we observe that these two firms do not invest in self-improvement technologies for cost higher than \$37.5 per TCO2e. For cost equal or lower than \$37.5 only Parsley will begin to invest in self-improvement measures in 2017.

		Variation (%)	-50%	-25%	0%	25%	50%
		Abatement Cost (C2)	$25.00	$37.50	$50.00	$62.50	$75.00
		Total Cost ($)	$134,270,938	$141,492,921	$144,136,504	$143,955,725	$144,119,108
		TC (%)	-7%	-2%	0%	0%	0%
Diamondback Energy	Emissions Purchased at Cap and Trade	t = 2016	89,819	89,817	89,818	89,823	89,824
		t = 2017	430,770	430,771	430,771	430,766	430,765
		t = 2018	0	0	0	0	0
		t = 2019	0	0	0	0	0
		t = 2020	0	0	0	0	0
	Emissions reduced with Self Improvement	t = 2016	1	1	1	1	1
		t = 2017	1	1	1	1	1
		t = 2018	1	1	1	1	1
		t = 2019	1	1	1	1	1
		t = 2020	1	1	1	1	1
Parsley Energy	Emissions Purchased at Cap and Trade	t = 2016	97,302	181,861	237,750	568,703	269,831
		t = 2017	0	0	330,952	0	298,872
		t = 2018	0	0	0	0	0
		t = 2019	0	0	0	0	0
		t = 2020	0	0	0	0	0
	Emissions reduced with Self Improvement	t = 2016	0	0	0	0	0
		t = 2017	471,401	386,842	0	0	0
		t = 2018	0	0	0	0	0
		t = 2019	0	0	0	0	0
		t = 2020	0	0	0	0	0

Table 13. Sensitivity analysis for abatement cost of Venting and Flaring.

It is important to note that the total cost is not very sensitive to changes in this parameter. The decrease of 50% in the value of abatement costs for venting and flaring only produces a decrease of 7% of the total optimum cost.

Abatement Measures for Controlling Emissions from Pneumatic Devices

Three facilities are emitting methane particles from pneumatic devices as their major source; they are Cimarex, EnverVest, and Yates (YPC). Total cost is more sensitive to decreases in abatement expenses for this particular technology than increases. We observe that when the cost decreases by 50%, the total optimum cost will decrease to about 31%, but it will only increase about 19% for increases of 50% in costs. In the case of Cimarex facility, the change in abatement costs will impact the combination of emissions reduction achieved by purchasing permits in the cap and trade and by self-improvement measures, but this company only invests in both options during 2016. In the case of EnverVest, only when the abatement costs are lower than $20 per TCO2e, the company will select reducing emissions exclusively with technology improvement. In the case of Yates, this facility will prefer only self-improvement measures for an abatement cost equals or less than $30 per TCO2e.

		Variation (%)	-50%	-25%	0%	25%	50%
		Abatement Cost (C2)	$20.00	$30.00	$40.00	$50.00	$60.00
		Total Cost ($)	$99,244,984	$125,657,201	$144,136,504	$159,500,961	$171,466,948
		TC (%)	-31%	-13%	0%	11%	19%
Cimarex Energy	Emissions Purchased at Cap and Trade	t = 2016	218,497	548,977	651,680	748,098	806,245
		t = 2017	0	0	0	0	0
		t = 2018	0	0	0	0	0
		t = 2019	0	0	0	0	0
		t = 2020	0	0	0	0	0
	Emissions reduced with Self Improvement	t = 2016	915,899	585,419	482,716	386,298	328,151
		t = 2017	0	0	0	0	0
		t = 2018	0	0	0	0	0
		t = 2019	0	0	0	0	0
		t = 2020	0	0	0	0	0
EnverVest Operating	Emissions Purchased at Cap and Trade	t = 2016	0	295,290	396,606	495,262	553,509
		t = 2017	0	0	0	0	0
		t = 2018	0	0	0	0	0
		t = 2019	0	0	0	0	0
		t = 2020	0	0	0	0	0
	Emissions reduced with Self Improvement	t = 2016	881,660	586,370	485,054	386,398	328,151
		t = 2017	0	0	0	0	0
		t = 2018	0	0	0	0	0
		t = 2019	0	0	0	0	0
		t = 2020	0	0	0	0	0
Yates Petroleum	Emissions Purchased at Cap and Trade	t = 2016	0	0	64,895	166,443	224,828
		t = 2017	0	0	0	0	0
		t = 2018	0	0	0	0	0
		t = 2019	0	0	0	0	0
		t = 2020	0	0	0	0	0
	Emissions reduced with Self Improvement	t = 2016	552,979	552,979	488,083	386,535	328,151
		t = 2017	0	0	0	0	0
		t = 2018	0	0	0	0	0
		t = 2019	0	0	0	0	0
		t = 2020	0	0	0	0	0

Table 14. Sensitivity analysis for abatement cost of Pneumatic Devices.

Abatement Measures for Controlling Emissions from Atmospheric Tanks

For three facilities considered in the sample, COG, Endeavor and Devon, the major source of methane emissions is recorded as gas from produced oil sent to atmospheric tanks by EPA. The initial optimum solution obtained for these facilities at $35 per TCO2e as abatement cost, shows that none of them selected to participate in the cap and trade market, and all the emissions reduction required was satisfied by self-improvement measures taken in the year 2016. Therefore, it is reasonable to anticipate no change in the value of decision variables for lower abatement costs, which is verified in the sensitivity analysis presented in Table 14. Only the total optimum cost is impacted by including lower values for this parameter, for example, a decrease of 13% in total cost caused by a decrease of 50% in the abatement cost for atmospheric tanks. Nevertheless, when the value of the abatement cost increases significantly, for example over 50%, all these facilities decide to participate in the cap and trade system to satisfy part of their emissions requirement. When the abatement cost increases in 86% (to over $65 TCO2e) none of these facilities has the incentive to invest in abatement measures to reduce emissions.

		Variation (%)	-50%	0%	25%	50%	86%
		Abatement Cost (C2)	$17.50	$35.00	$43.75	$52.50	$65.00
		Total Cost ($)	$125,723,830	$144,136,504	$152,649,738	$157,916,651	$159,212,257
		TC (%)	-13%	0%	6%	10%	10%
COG Operating	Emissions Purchased at Cap and Trade	t = 2016	0	0	0	42,064	171,981
		t = 2017	0	0	0	36,899	66,078
		t = 2018	0	0	0	0	0
		t = 2019	0	0	0	0	0
		t = 2020	0	0	0	0	0
	Emissions reduced with Self Improvement	t = 2016	238,059	238,059	238,059	159,096	0
		t = 2017	0	0	0	0	0
		t = 2018	0	0	0	0	0
		t = 2019	0	0	0	0	0
		t = 2020	0	0	0	0	0
Endeavor Energy	Emissions Purchased at Cap and Trade	t = 2016	0	0	188,809	434,620	548,188
		t = 2017	0	0	0	0	0
		t = 2018	0	0	0	0	0
		t = 2019	0	0	0	0	0
		t = 2020	0	0	0	0	0
	Emissions reduced with Self Improvement	t = 2016	548,188	548,188	359,380	113,568	0
		t = 2017	0	0	0	0	0
		t = 2018	0	0	0	0	0
		t = 2019	0	0	0	0	0
		t = 2020	0	0	0	0	0
Devon Energy	Emissions Purchased at Cap and Trade	t = 2016	0	0	0	1,443	85,126
		t = 2017	0	0	0	0	23,308
		t = 2018	0	0	0	0	0
		t = 2019	0	0	0	0	0
		t = 2020	0	0	0	0	0
	Emissions reduced with Self Improvement	t = 2016	108,434	108,434	108,434	106,991	0
		t = 2017	0	0	0	0	0
		t = 2018	0	0	0	0	0
		t = 2019	0	0	0	0	0
		t = 2020	0	0	0	0	0

Table 15. Sensitivity analysis for abatement cost of Atmospheric Tanks.

Sensitivity analysis of abatement costs provides relevant information to identify at what values companies are encouraged to start investing more in self-improvement technologies to reduce emissions, especially when market-based alternatives are not available.

Sensitivity on Total Emissions Reduction Target (*Q*)

The total emissions reduction set as the goal for the planned horizon could be very controversial and primarily a political decision, which if it is not set correctly might underestimate the total requirement needed to achieve efficiency. To evaluate the impact on the total cost of setting different goals (*Q*), I performed several numerical experiments by changing the price of emission credits in the cap and trade market for different targets and computing the total cost associated with each new optimal solution. This sensitivity analysis will let us know if there is a correct amount of *Q** to be set as emission reduction for the period 2016-2020. For the analysis of this part, I set the baseline case for the emission prices observed in the cap and trade market as P = C^1, which is the same set of prices used in all the previous optimization cases. Then I ran the model and computed the minimum cost associated with different levels of prices such as 0.5P, 0.75P, P, 1.5P, and 1.75P, and for different levels of target emission reductions Q. The main results are shown in the following Table 15 and Table 16.

	0.5 P	0.75 P	P = C (base case)	1.5 P	1.75 P
$C_{1(2016)}$	8.6	12.8	17	25.7	29.9
$C_{1(2017)}$	8.8	13.2	18	26.5	30.9
$C_{1(2018)}$	11.5	17.2	23	34.5	40.2
$C_{1(2019)}$	11.2	16.8	22	33.6	39.2
$C_{1(2020)}$	12.0	17.9	24	35.9	41.9

Table 16. Price levels of cap and trade permit selected for sensitivity analysis.

Q Target (TCO2e)	C_1 = 0.5P	C1 = 0.75P	C_1 = P	C_1 = 1.5P	C_1 = 1.75 P
1,000,000	79,959,872	102,092,217	119,993,454	154,835,546	172,094,111
1,500,000	94,432,853	107,344,557	120,566,893	146,500,959	159,560,524
2,000,000	111,365,891	122,874,963	133,401,422	155,435,967	166,455,647
2,350,540	126,009,365	135,997,040	144,136,504	165,960,070	175,947,756
3,000,000	151,207,280	157,804,451	164,447,364	177,822,520	184,377,513
3,500,000	171,886,483	176,429,499	181,335,480	189,894,592	194,461,218
4,000,000	193,428,352	195,823,580	198,733,955	202,964,191	205,398,496
4,500,000	234,748,974	218,871,902	224,931,438	219,552,271	219,779,056

Table 17. Total minimum cost associated with different targets Q for different price levels.

As shown in Figure 13, when the prices of emission permits in the market are high, for example 1.5P and 1.75P curves, there is an evident level of Q that minimizes the total cost, in this case the right amount of emissions to set as goal should be 1.5 million of TCO2e, otherwise setting the goal too low or too high will be inefficient. When prices in the market are low, the tradeoff between *Q* and total cost disappears.

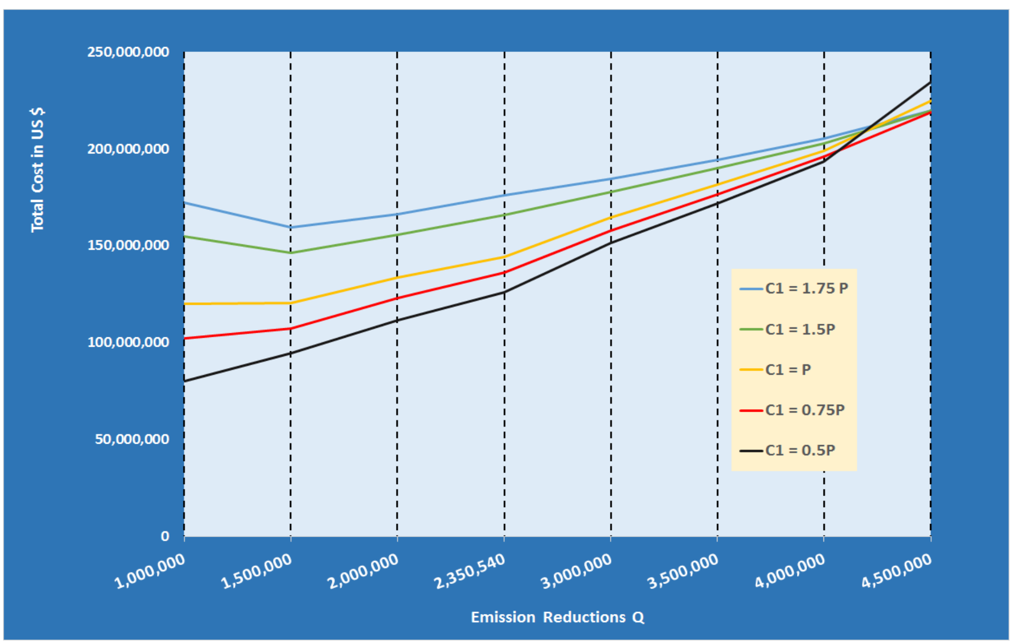


Figure 13. Total cost curves for different emission reduction targets Q.

Chapter 5: Conclusions

Market-based environmental policies involve a fundamental distributional question: "How should we divide up the 'pie' created by placing a price on emissions?" A cap and trade system regulates the tradeoff between distribution and efficiency. It offers the "best of both worlds."

A cap and trade option is seen as an economically preferable alternative to more costly command and control regulations because setting a cap, provides certainty that total emissions will remain below prespecified specific level, the upper limit can be tightened over time and cap and trade can operate at local, regional or national scales.

The cost of achieving substantial emission reductions in the future will depend importantly on the availability and cost of low or zero-emitting technologies. A cap and trade system that considers limits extending into the future provides important price signals and therefore incentives for firms to invest in the development and deployment of such technologies, thereby reducing the future costs of achieving emission reductions. (Stavins, 2008).

Based on previous cap and trade experiences, some of the most relevant lessons learned are:

Cap and Trade programs have been proven to be environmentally and economically more effective compared to traditional command and control approaches, and have led to substantial technological change and process innovations (Schmalensee and Stavins 2015).

Regulators must promote more confidence and trust by adopting a full commitment to the program and guaranteeing consistency in the market and their policies.

From theory and experience, it is clear that a robust market requires a cap that is significantly below Business as Usual (BAU) emissions.

The allocation of allowances is certainly a major political issue, because of the large distributional impacts that can be involved. Free allowance allocation has proven to be a better way to build political support, although it foregoes the opportunity to cut the program's overall social cost by auctioning allowances and using the proceeds to cut other distortionary taxes. Periodic evaluation is critical to keep programs on track.

The success of any cap and trade system depends heavily on political liability and the existence of a proper administration. This system is vulnerable to manipulation by the political power of energy interest and environmental activist groups, and for this reason, the establishment of clear rules backed by ongoing government commitment are critical for its survival.

The outcome of this research provides a distinctive and significant evidence to base public policy decisions related to emission reductions, and the model is a necessary tool to support analysis of various environmental compliance issues present in the oil and gas industry.

The rules for emissions regulation in the oil and gas industry will keep changing, and the concept of externalities will become even more critical. We are far from the knowledge needed to make good climate policy to achieve a strategy that balances sustainability with economic development, and I hope this research helps on reducing that gap.

Appendix A: All facilities reported with methane emissions by EPA during 2014 in the Permian Basin

#	FACILITY NAME	GHGRP ID	BASIN NAME/NUMBER	PARENT COMPANIES	Emissions	SUBPARTS
1	Diamondback E&P LLC	1009434	430 - Permian Basin	Diamondback Energy (100%);	432,156	W
2	EnerVest Operating L.L.C.- 430 HighMount Permian	1008475	430 - Permian Basin	LOEWS CORP (100%);	385,869	W
3	Cimarex Energy Co. 430 Permian	1008544	430 - Permian Basin	CIMAREX ENERGY CO (100%);	253,901	W
4	COG Operating LLC 430 Permian Basin	1009707	430 - Permian Basin	COG OPERATING, LLC (100%);	239,991	W
5	YPC 430 Permian Basin (Yates)	1008229	430 - Permian Basin	Yates Petroleum Corporation (100%);	227,661	W
6	Endeavor Energy Resources LP 430 Permian Basin	1011659	430 - Permian Basin	Endeavor Energy Resources LP (100%);	223,301	W
7	430 Permian Basin DEC (DEVON)	1008290	430 - Permian Basin	DEVON ENERGY (100%);	215,920	W
8	Parsley Energy, Inc. 430 Permian Basin	1011555	430 - Permian Basin	PARSLEY ENERGY INC (100%);	196,632	W
9	Pioneer Natural Resources USA, Inc. Permian	1008607	430 - Permian Basin	PIONEER NATURAL RESOURCES USA, INC (100%);	184,660	W
10	SandRidge 430 Permian Basin	1008809	430 - Permian Basin	SandRidge Exploration and Production, LLC (100%);	173,911	W
11	EOG Resources, Inc. 430 Permian basin	1008351	430 - Permian Basin	EOG Resources, Inc. (100%);	163,364	W
12	Permian Basin - AAPG Province 430 (ANADARKO)	1008449	430 - Permian Basin	ANADARKO PETROLEUM CORP (100%);	149,880	W
13	Cimarex Energy Co. of Colorado 430 Permian	1008700	430 - Permian Basin	CIMAREX ENERGY CO (100%);	134,548	W
14	EP Energy E&P 430 Permian Basin	1007777	430 - Permian Basin	EP Energy E&P Company, LP (100%);	124,306	W
15	XTO Energy Inc 430 Permian (EXXON)	1009390	430 - Permian Basin	EXXONMOBIL CORP (100%);	108,679	W
16	Apache Corp. Permian - Permian Basin 430	1009391	430 - Permian Basin	APACHE CORPORATION (100%);	102,581	W
17	Approach Operating, LLC 430 Permian Basin	1008456	430 - Permian Basin	Approach Resources, INC (100%);	98,476	W
18	Permian Operations - Shell Exploration & Production Company	1010588	430 - Permian Basin	SWEPI LP (100%);	94,891	W
19	Chevron MCA 430 Permian Basin	1009240	430 - Permian Basin	CHEVRON CORP (100%);	83,610	W
20	BOPCO, L.P. 430 Permian basin	1009030	430 - Permian Basin	BOPCO, LP (100%);	78,662	W
23	ConocoPhillips' Permian (430)	1007479	430 - Permian Basin	CONOCO PHILLIPS (100%);	64,169	UU,W
21	Compass Production Partners, LP - Permian Basin #430	1008959	430 - Permian Basin	COMPASS PRODUCTION PARTNERS LP (100%);	76,252	W
22	Discovery Natural Resources LLC - 430 Permian Basin	1010294	430 - Permian Basin	Discovery Natural Resources, LLC (100%);	74,049	W
24	American Energy - Permian Basin, LLC	1011394	430 - Permian Basin	American Energy Partners LP (100%);	61,527	W
25	430 Permian RKI Exploration & Production	1009039	430 - Permian Basin	RKI EXPLORATION & PRODUCTION LLC (100%);	54,912	W
26	Breitburn Operating LP 430 Permian	1009813	430 - Permian Basin	BREITBURN ENERGY CO LP (100%);	54,145	W
27	Energen Resources Corporation 430 Permian Basin	1008836	430 - Permian Basin	ENERGEN CORP (100%);	52,054	UU,W
28	Legacy Reserves Basin 430	1011498	430 - Permian Basin	Legacy Reserves Operating LP (100%);	50,545	W
29	Southwest Royalties, Inc. - 430 Permian Basin	1006884	430 - Permian Basin	Clayton Williams Energy, Inc. (100%);	50,453	W
30	Nadel and Gussman Permian Basin No. 430	1009788	430 - Permian Basin	Nadel & Gussman, LLC (100%);	48,074	W
31	Linn Energy 430 Permian Basin	1008365	430 - Permian Basin	Linn Energy, LLC (100%);	45,013	W
32	Laredo Petroleum Basin 430	1009056	430 - Permian Basin	Laredo Petroleum (100%);	44,162	W
33	Oxy Permian Basin - 430	1008141	430 - Permian Basin	OCCIDENTAL PETROLEUM CORP (100%);	43,281	W
34	Clayton Williams Energy, Inc. - 430 Permian Basin	1006886	430 - Permian Basin	Clayton Williams Energy, Inc. (100%);	37,331	W
35	Sheridan Production Company LLC 430 Permian Basin	1009846	430 - Permian Basin	Sheridan Production Company, LLC (100%);	35,724	W
36	J. Cleo Thompson & James Cleo Thompson, Jr. L.P. 430 Permian Basin	1007037	430 - Permian Basin	J. Cleo Thompson & James Cleo Thompson, Jr. L.P. (100%);	33,015	W
37	EQT Production - Basin 430	1011662	430 - Permian Basin	EQT CORP (100%);	29,050	W
38	Vanguard Basin 430 (Permian)	1011519	430 - Permian Basin	Vanguard Natural Resources, INCORPORATED (100%);	23,790	W
39	MERIT ENERGY CO LLC 430 PERMIAN BASIN	1009273	430 - Permian Basin	MERIT ENERGY CO, LLC (100%);	21,772	W
40	BHP Billiton Petrohawk Permian Basin, AAPG Basin 430	1008632	430 - Permian Basin	BHP Billiton Petroleum (North America) Inc. (100%);	20,253	W
41	SM Energy (Basin 430) Permian Basin	1009674	430 - Permian Basin	SM Energy Company (100%);	16,598	W
42	Basin 430 Midland	1008642	430 - Permian Basin	HUNT CONSOLIDATED, INC (100%);	15,404	W
43	Resolute Natural Resources Compnay, LLC 430 Permian Basin	1011735	430 - Permian Basin		13,279	W
44	Unit Petroleum 285 Permian Basin	1009339	430 - Permian Basin	Unit Petroleum Company (100%);	11,619	W
45	Fasken Oil and Ranch, Ltd. 430 Permian Basin	1009718	430 - Permian Basin	FASKEN OIL AND RANCH, LTD (100%);	10,537	UU,W
46	Newfield 430 Permian Basin	1008143	430 - Permian Basin	Newfield Exploration Company (100%);	10,395	W
47	Burnett Oil Co., Inc. 430 Permian Basin	1010784	430 - Permian Basin	Burnett Oil Co., Inc. (100%);	9,612	W
48	W&T Offshore, Inc. - Basin 430 (Permian Basin)	1010633	430 - Permian Basin	W&T Offshore, Inc. (100%);	6,242	W
49	Centennial Resource Production, LLC	1011690	430 - Permian Basin	Centennial Resource Production, LLC (100%);	5,152	W
50	Encana Oil & Gas - Permian Basin	1008331	430 - Permian Basin	ENCANA OIL & GAS (USA) INC (100%);	2,826	W
51	Hess Corporation - 430 - Permian Basin	1008634	430 - Permian Basin	Hess Corporation (100%);	2,438	W
52	Range Texas Production, LLC & Range Operating New Mexico, LLC - Basin 430	1008914	430 - Permian Basin	Range Texas Production, LLC (100%);	1,706	W
53	430 Permian Basin QEP Energy Company	1009691	430 - Permian Basin	EnerVest Operating, LLC (100%);	1,644	W
54	RSP Permian, LLC	1011846	430 - Permian Basin		936	W
55	430 Permian Basin	1009270	430 - Permian Basin	CHAPARRAL ENERGY, INC (100%);	119	W
56	Kinder Morgan Production 430 Permian Basin	1008248	430 - Permian Basin	Kinder Morgan (100%);	2	W
		Total			4,701,079	

Appendix B: EPA report of emissions Facility: Diamondback Energy.

Facility Name: Diamondback E&P LLC
Facility Identifier:
Facility Reporting Year: 2014
Facility Location:
Address: 500 West Texas Suite 1200
City: Midland
State: TX
Postal Code: 79701

Facility Site Details:
CO2 equivalent emissions from facility subparts C-II, SS, and TT (metric tons): 1134747.1
CO2 equivalent emissions from supplier subparts LL-QQ (metric tons):
Biogenic CO2 emissions from facility subparts C-II, SS, and TT (metric tons): 0
Cogeneration Unit Emissions Indicator: NA
GHG Report Start Date: 2014-01-01
GHG Report End Date: 2014-12-31
Description of Changes to Calculation Methodology:
Did you use BAMM in this reporting year as a result of becoming newly subject to a Part 98 subpart due to amendments to global warming potentials (Table A-1 of Part 98) finalized on November 29, 2013? N
Part 75 Biogenic Emissions Indication:
Plant Code Indicator: N
Primary NAICS Code: 211111
Second Primary NAICS Code:

Parent Company Details:
Parent Company Name: Diamondback Energy
Address: 500 W. Texas, Ste. 1200, Midland, TX 79701
Percent Ownership Interest: 100

Subpart W: Petroleum and Natural Gas Systems

Gas Information Details

Gas Name	Other Gas Name	Gas Quantity	Own Result?
Methane		17286.25 (Metric Tons)	
Nitrous Oxide		3.414 (Metric Tons)	
Carbon Dioxide		701573.5 (Metric Tons)	

SubpartWSummaryDetails:

Industry Segment Number	2
Industry Segment Name	Onshore petroleum and natural gas production [98.230(a)(2)]
Annual throughput [98.236(d)] Gaseous Throughput (MMscf)	
Annual throughput [98.236(d)] Liquid Throughput (thousand barrels)	
Total Reported CO2 Emissions (mt CO2)	701573.5
Total Reported CH4 Emissions (mt CO2e)	432156.3
Total Reported N2O Emissions (mt CO2e)	1017.3

Total Reported Emissions (mt CO2e)	1134747.0

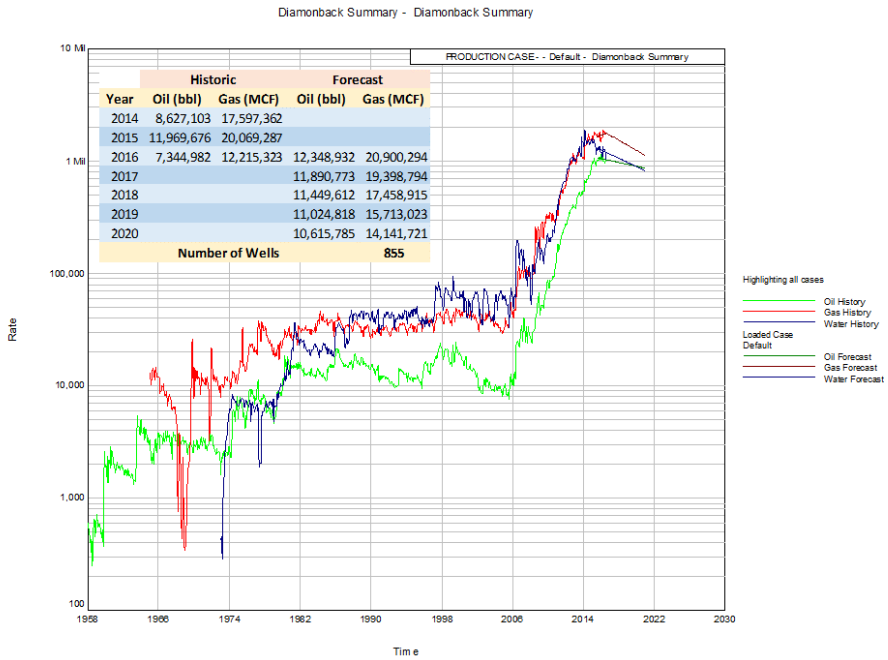
SubpartWSourceReportingFormRowDetails:

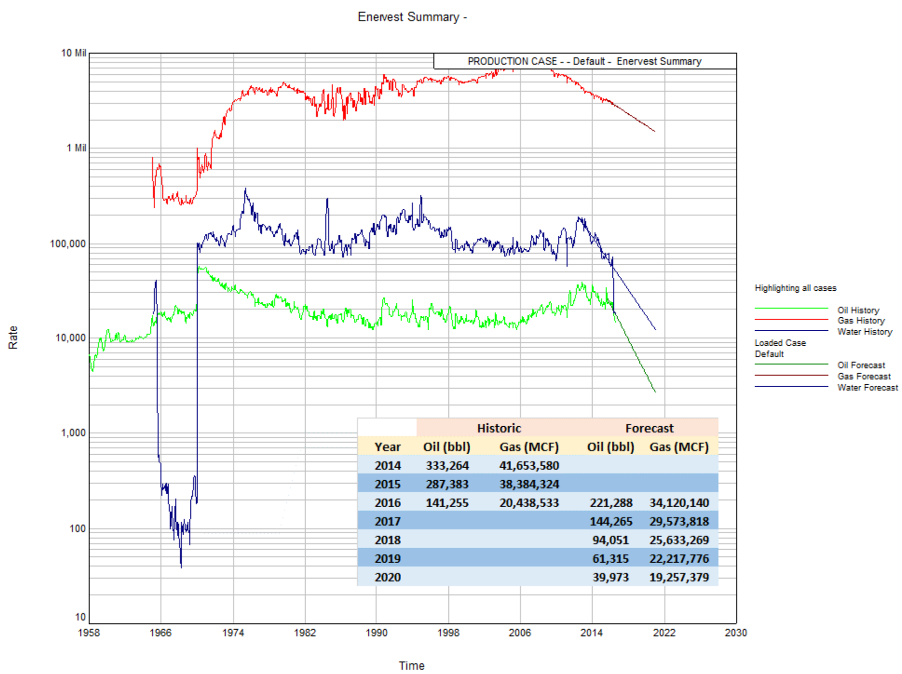
Source Reporting Form	Sub-Basin Selection
Required for Selected Industry Segment	Yes
Total Reported CO2 Emissions (mt CO2)	N/A
Total Reported CH4 Emissions (mt CO2e)	N/A
Total Reported N2O Emissions (mt CO2e)	N/A
Total Reported Emissions (mt CO2e)	N/A
Source Reporting Form	Natural Gas Pneumatic Devices [98.236(c)(1)]
Required for Selected Industry Segment	Yes
Total Reported CO2 Emissions (mt CO2)	90.2
Total Reported CH4 Emissions (mt CO2e)	14696.6
Total Reported N2O Emissions (mt CO2e)	N/A
Total Reported Emissions (mt CO2e)	14786.8
Source Reporting Form	Natural Gas Driven Pneumatic Pumps [98.236(c)(2)]
Required for Selected Industry Segment	Yes
Total Reported CO2 Emissions (mt CO2)	0.0
Total Reported CH4 Emissions (mt CO2e)	0.0
Total Reported N2O Emissions (mt CO2e)	N/A
Total Reported Emissions (mt CO2e)	0.0
Source Reporting Form	Acid Gas Removal Units [98.236(c)(3)]
Required for Selected Industry Segment	Yes
Total Reported CO2 Emissions (mt CO2)	0.0
Total Reported CH4 Emissions (mt CO2e)	N/A
Total Reported N2O Emissions (mt CO2e)	N/A
Total Reported Emissions (mt CO2e)	0.0
Source Reporting Form	Dehydrators [98.236(c)(4)]
Required for Selected Industry Segment	Yes
Total Reported CO2 Emissions (mt CO2)	0.0
Total Reported CH4 Emissions (mt CO2e)	0.0
Total Reported N2O Emissions (mt CO2e)	0.0
Total Reported Emissions (mt CO2e)	0.0
Source Reporting Form	Well Venting for Liquids Unloading [98.236(c)(5)]
Required for Selected Industry Segment	Yes
Total Reported CO2 Emissions (mt CO2)	0.0
Total Reported CH4 Emissions (mt CO2e)	0.0
Total Reported N2O Emissions (mt CO2e)	N/A
Total Reported Emissions (mt CO2e)	0.0
Source Reporting Form	Gas Well Completions and Workovers [98.236(c)(6)]
Required for Selected Industry Segment	Yes
Total Reported CO2 Emissions (mt CO2)	2.6
Total Reported CH4 Emissions (mt CO2e)	391.4

Total Reported N2O Emissions (mt CO2e)	0.0
Total Reported Emissions (mt CO2e)	394.0
Source Reporting Form	Blowdown Vent Stacks [98.236(c)(7)]
Required for Selected Industry Segment	No
Total Reported CO2 Emissions (mt CO2)	0.0
Total Reported CH4 Emissions (mt CO2e)	0.0
Total Reported N2O Emissions (mt CO2e)	N/A
Total Reported Emissions (mt CO2e)	0.0
Source Reporting Form	Gas from Produced Oil Sent to Atmospheric Tanks [98.236(c)(8)]
Required for Selected Industry Segment	Yes
Total Reported CO2 Emissions (mt CO2)	31.6
Total Reported CH4 Emissions (mt CO2e)	468.9
Total Reported N2O Emissions (mt CO2e)	5.0
Total Reported Emissions (mt CO2e)	505.6
Source Reporting Form	Transmission Tanks [98.236(c)(9)]
Required for Selected Industry Segment	No
Total Reported CO2 Emissions (mt CO2)	0.0
Total Reported CH4 Emissions (mt CO2e)	0.0
Total Reported N2O Emissions (mt CO2e)	0.0
Total Reported Emissions (mt CO2e)	0.0
Source Reporting Form	Well Testing Venting and Flaring [98.236(c)(10)]
Required for Selected Industry Segment	Yes
Total Reported CO2 Emissions (mt CO2)	122397.9
Total Reported CH4 Emissions (mt CO2e)	391507.8
Total Reported N2O Emissions (mt CO2e)	698.6
Total Reported Emissions (mt CO2e)	514604.3
Source Reporting Form	Associated Gas Venting and Flaring [98.236(c)(11)]
Required for Selected Industry Segment	Yes
Total Reported CO2 Emissions (mt CO2)	0.0
Total Reported CH4 Emissions (mt CO2e)	0.0
Total Reported N2O Emissions (mt CO2e)	0.0
Total Reported Emissions (mt CO2e)	0.0
Source Reporting Form	Flare Stacks [98.236(c)(12)]
Required for Selected Industry Segment	Yes
Total Reported CO2 Emissions (mt CO2)	548676.7
Total Reported CH4 Emissions (mt CO2e)	12693.9
Total Reported N2O Emissions (mt CO2e)	241.0
Total Reported Emissions (mt CO2e)	561611.6
Source Reporting Form	Centrifugal Compressors [98.236(c)(13)]
Required for Selected Industry Segment	Yes
Total Reported CO2 Emissions (mt CO2)	0.0
Total Reported CH4 Emissions (mt CO2e)	0.0
Total Reported N2O Emissions (mt CO2e)	0.0
Total Reported Emissions (mt CO2e)	0.0

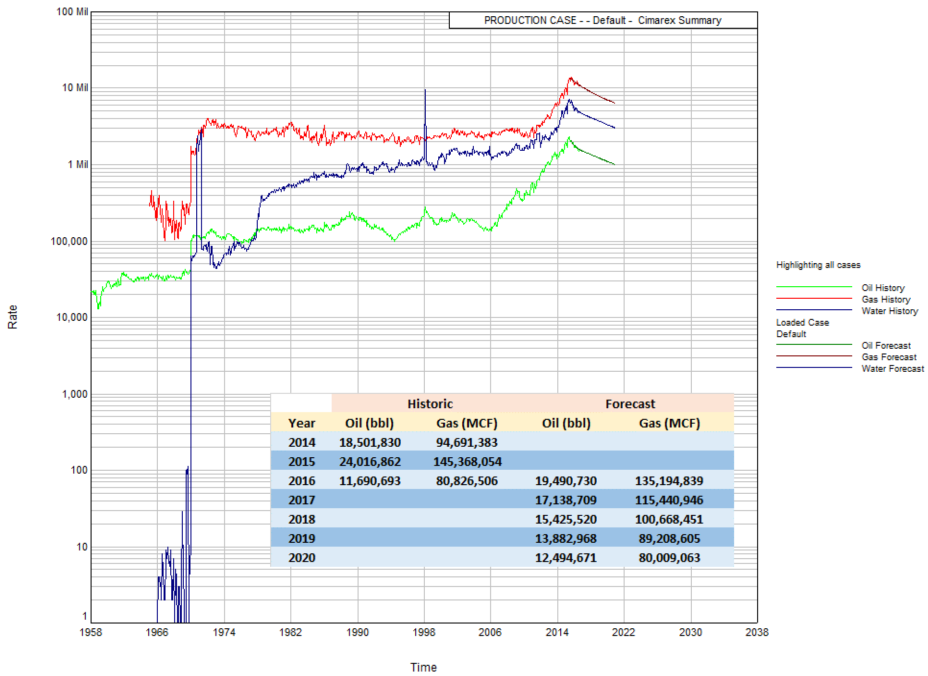
Source Reporting Form	Reciprocating Compressors [98.236(c)(14)]
Required for Selected Industry Segment	Yes
Total Reported CO2 Emissions (mt CO2)	0.2
Total Reported CH4 Emissions (mt CO2e)	41.0
Total Reported N2O Emissions (mt CO2e)	0.0
Total Reported Emissions (mt CO2e)	41.2
Source Reporting Form	Other Emissions from Equipment Leaks Estimated Using Emission Factors [98.236(c)(15)]
Required for Selected Industry Segment	Yes
Total Reported CO2 Emissions (mt CO2)	75.5
Total Reported CH4 Emissions (mt CO2e)	12319.4
Total Reported N2O Emissions (mt CO2e)	N/A
Total Reported Emissions (mt CO2e)	12394.9
Source Reporting Form	Local Distribution Companies [98.236(c)(16)]
Required for Selected Industry Segment	No
Total Reported CO2 Emissions (mt CO2)	0.0
Total Reported CH4 Emissions (mt CO2e)	0.0
Total Reported N2O Emissions (mt CO2e)	N/A
Total Reported Emissions (mt CO2e)	0.0
Source Reporting Form	Enhanced Oil Recovery Injection Pump Blowdown [98.236(c)(17)]
Required for Selected Industry Segment	Yes
Total Reported CO2 Emissions (mt CO2)	0.0
Total Reported CH4 Emissions (mt CO2e)	N/A
Total Reported N2O Emissions (mt CO2e)	N/A
Total Reported Emissions (mt CO2e)	0.0
Source Reporting Form	Enhanced Oil Recovery Hydrocarbon Liquids Dissolved CO2 [98.236(c)(18)]
Required for Selected Industry Segment	Yes
Total Reported CO2 Emissions (mt CO2)	0.0
Total Reported CH4 Emissions (mt CO2e)	N/A
Total Reported N2O Emissions (mt CO2e)	N/A
Total Reported Emissions (mt CO2e)	0.0
Source Reporting Form	Onshore Petroleum and Natural Gas Production and Natural Gas Distribution Combustion Emissions [98.236(c)(19)]
Required for Selected Industry Segment	Yes
Total Reported CO2 Emissions (mt CO2)	30298.8
Total Reported CH4 Emissions (mt CO2e)	37.2
Total Reported N2O Emissions (mt CO2e)	72.6
Total Reported Emissions (mt CO2e)	30408.6
Source Reporting Form	Offshore Sources [98.236(b)]
Required for Selected Industry Segment	No
Total Reported CO2 Emissions (mt CO2)	0.0
Total Reported CH4 Emissions (mt CO2e)	0.0

Appendix C: Declining curves for the top facilities producing in the Permian Basin and included in the final sample



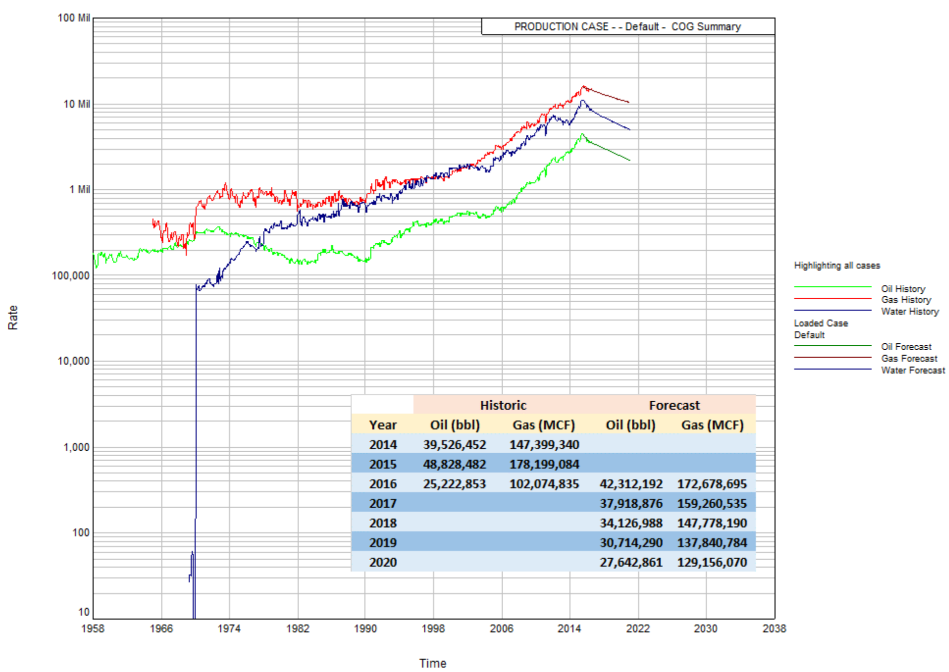


Cimarex Summary -



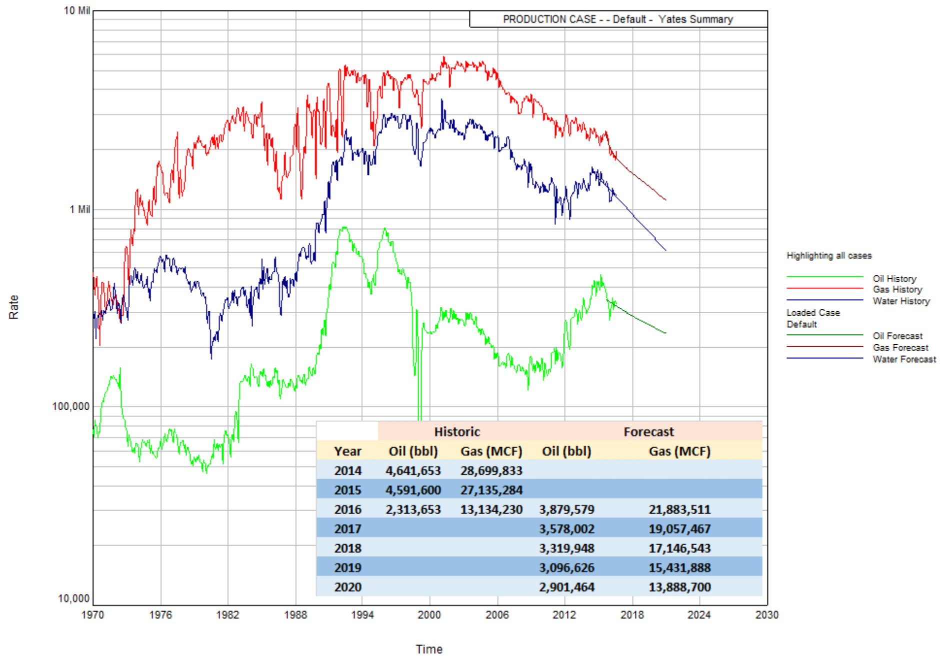
	Historic		Forecast	
Year	Oil (bbl)	Gas (MCF)	Oil (bbl)	Gas (MCF)
2014	18,501,830	94,691,383		
2015	24,016,862	145,368,054		
2016	11,690,693	80,826,506	19,490,730	135,194,839
2017			17,138,709	115,440,946
2018			15,425,520	100,668,451
2019			13,882,968	89,208,605
2020			12,494,671	80,009,063

COG Summary -



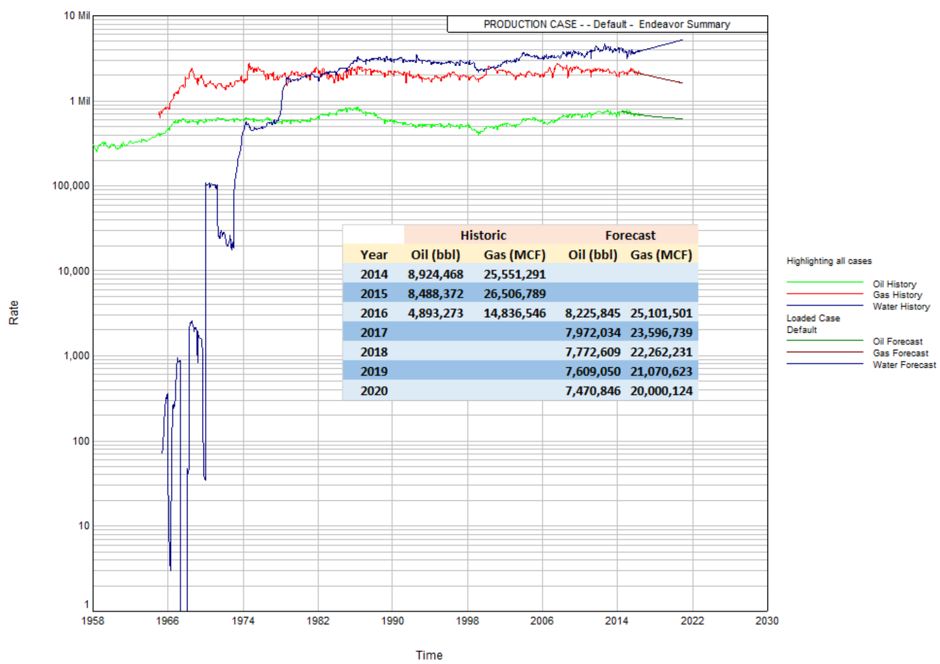
	Historic		Forecast	
Year	Oil (bbl)	Gas (MCF)	Oil (bbl)	Gas (MCF)
2014	39,526,452	147,399,340		
2015	48,828,482	178,199,084		
2016	25,222,853	102,074,835	42,312,192	172,678,695
2017			37,918,876	159,260,535
2018			34,126,988	147,778,190
2019			30,714,290	137,840,784
2020			27,642,861	129,156,070

Yates Summary -



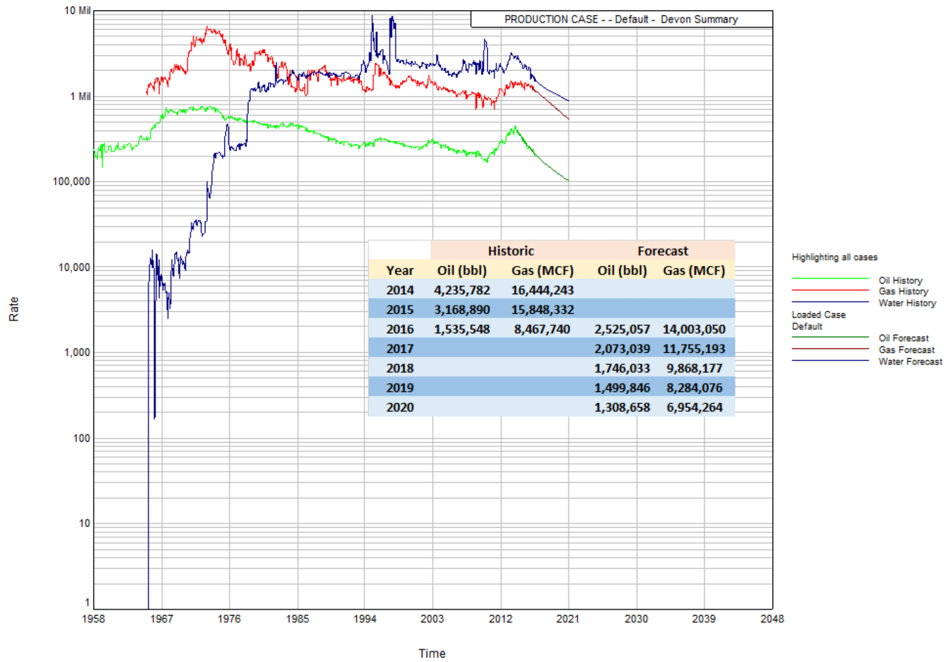
	Historic		Forecast	
Year	Oil (bbl)	Gas (MCF)	Oil (bbl)	Gas (MCF)
2014	4,641,653	28,699,833		
2015	4,591,600	27,135,284		
2016	2,313,653	13,134,230	3,879,579	21,883,511
2017			3,578,002	19,057,467
2018			3,319,948	17,146,543
2019			3,096,626	15,431,888
2020			2,901,464	13,888,700

Endeavor Summary -



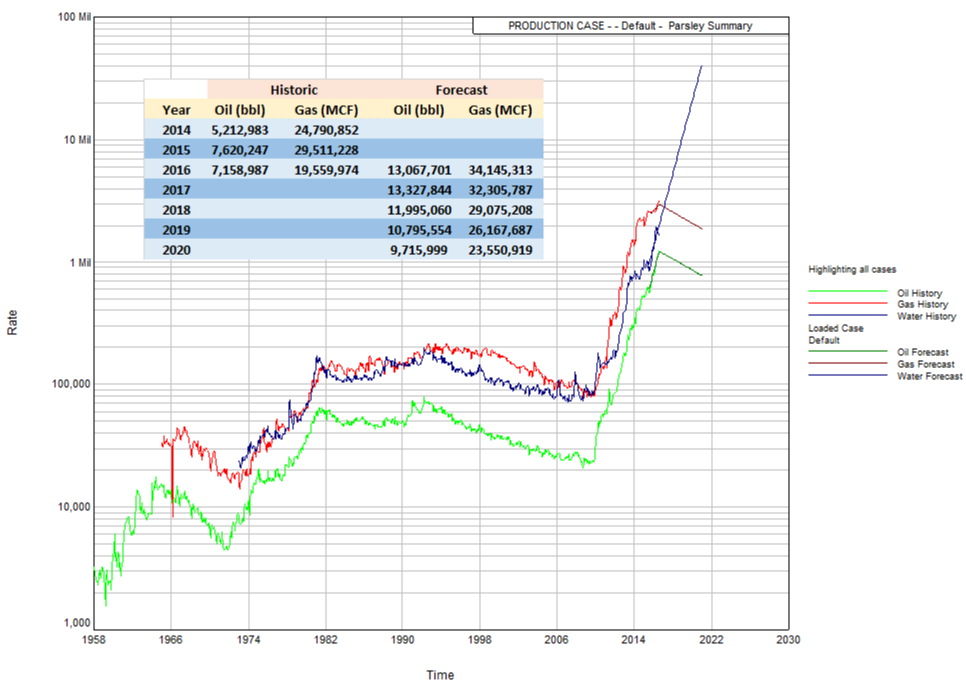
	Historic		Forecast	
Year	Oil (bbl)	Gas (MCF)	Oil (bbl)	Gas (MCF)
2014	8,924,468	25,551,291		
2015	8,488,372	26,506,789		
2016	4,893,273	14,836,546	8,225,845	25,101,501
2017			7,972,034	23,596,739
2018			7,772,609	22,262,231
2019			7,609,050	21,070,623
2020			7,470,846	20,000,124

Devon Summary -



	Historic		Forecast	
Year	Oil (bbl)	Gas (MCF)	Oil (bbl)	Gas (MCF)
2014	4,235,782	16,444,243		
2015	3,168,890	15,848,332		
2016	1,535,548	8,467,740	2,525,057	14,003,050
2017			2,073,039	11,755,193
2018			1,746,033	9,868,177
2019			1,499,846	8,284,076
2020			1,308,658	6,954,264

Parsley Summary -



	Historic		Forecast	
Year	Oil (bbl)	Gas (MCF)	Oil (bbl)	Gas (MCF)
2014	5,212,983	24,790,852		
2015	7,620,247	29,511,228		
2016	7,158,987	19,559,974	13,067,701	34,145,313
2017			13,327,844	32,305,787
2018			11,995,060	29,075,208
2019			10,795,554	26,167,687
2020			9,715,999	23,550,919

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